STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1146
DOCKET NO. E-7, SUB 819
DOCKET NO. E-7, SUB 1152
DOCKET NO. E-7, SUB 1110

DOCKET NO. E-7, SUB 1146 In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina DOCKET NO. E-7, SUB 819 In the Matter of Amended Application by Duke Energy Carolinas, LLC, for Approval of Decision to Incur Nuclear Generation Project Development Costs DOCKET NO. E-2, SUB 1152 In the Matter of Petition of Duke Energy Carolinas, LLC, for an Order Approving a Job Retention Rider DOCKET NO. E-7, SUB 1110 In the Matter of Joint Application by Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, for Accounting Order to Defer Environmental Compliance Costs	ORDER ACCEPTING STIPULATION, DECIDING CONTESTED ISSUES, AND REQUIRING REVENUE REDUCTION

HEARD: Tuesday, January 16, 2018, at 7:00 p.m., in the Macon County Courthouse, Courtroom A, 5 W. Main Street, Franklin, North Carolina

Wednesday, January 24, 2018, at 7:00 p.m., in the Guilford County Courthouse, Courtroom 1C, 201 S. Eugene Street, Greensboro, North Carolina

Tuesday, January 30, 2018, at 6:30 p.m., in the Mecklenburg County Courthouse, 832 E. 4th Street, Charlotte, North Carolina

Monday, March 5, 2018, at 1:30 p.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding; Commissioners ToNola D. Brown-Bland, Jerry C. Dockham, James G. Patterson, Lyons Gray, and Daniel G. Clodfelter

APPEARANCES:

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For North Carolina Farm Bureau Federation, Inc. (NCFB):

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For the North Carolina Justice Center (NC Justice Center), North Carolina Housing Coalition (NC Housing Coalition), Natural Resources Defense Council (NRDC), and Southern Alliance for Clean Energy (SACE) (collectively, NC Justice Center, et al.):

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BY THE COMMISSION: On July 25, 2017, pursuant to Commission Rule R1-17(a), Duke Energy Carolinas, LLC (DEC or the Company), filed notice of its intent to file a general rate case application. On August 25, 2017, the Company filed its Application to Adjust Retail Rates and Request for an Accounting Order (the Application), along with a Rate Case Information Report, Commission Form E-1 (Form E-1), and the direct testimony and exhibits of David B. Fountain, North Carolina President, DEC; Jane L. McManeus, Director of Rates & Regulatory Planning, DEC; Scott L. Batson, Senior Vice President of Nuclear Operations, Duke Energy Corporation (Duke Energy);[1] Stephen G. De May, Senior Vice President Tax and Treasurer, Duke Energy Business Services,

[1] DEC is a wholly owned subsidiary of Duke Energy Corporation. Tr. Vol. 6, p. 155.

LLC (DEBS);[2] James H. Cowling, Director of Outdoor Lighting for DEC, DEBS; Nils J. Diaz, Managing Director, the ND2 Group, LLC; David L. Doss Jr., Director of Electric Utilities and Infrastructure Accounting, DEBS; Christopher M. Fallon, Vice President, Duke Energy Renewables and Commercial Portfolio (and former Vice President Nuclear Development), Duke Energy; Janice Hager, President, Janice Hager Consulting; Robert B. Hevert, Partner, ScottMadden, Inc.; Retha Hunsicker, Vice President Customer Operations, Customer Information Systems, DEBS; Jon F. Kerin, Vice President Governance and Operations Support, Coal Combustion Products, DEBS; Julius A. Wright, Managing Partner, J.A. Wright & Associates, LLC; Kimberly D. McGee, Rates & Regulatory Strategy Manager, DEC and Duke Energy Progress, LLC (DEP); Joseph A. Miller Jr., Vice President of Central Services, DEBS; Robert M. Simpson III, Director Grid Improvement Plan Integration for Duke Energy's Regulated Utilities Operations, DEP; Donald L. Schneider, Jr., General Manager, Advanced Metering Infrastructure (AMI) Program Management, DEBS; and Michael J. Pirro, Manager of Southeast Pricing & Regulatory Solutions, DEC, DEP, and Duke Energy Florida, LLC.

Petitions to intervene were filed by NCSEA on July 26, 2017; CIGFUR III on August 8, 2017; CUCA on August 9, 2017; the Rate-Paying Neighbors on August 23, 2017; EDF on August 25, 2017; NCFB on September 6, 2017; NC WARN on September 7, 2017; Sierra Club on September 18, 2017; Kroger on September 19, 2017; ASU on September 29, 2017; NCLM on October 3, 2017; Piedmont EMC, Rutherford EMC, Haywood EMC, and Blue Ridge EMC on October 16, 2017; the Commercial Group on October 31, 2017; Tech Customers on November 2, 2017; Concord and Kings Mountain on November 17, 2017; NC Justice Center, et al. on December 19, 2017; and Durham on January 3, 2018. Notice of intervention was filed by the Office of the Attorney General (AGO) on August 31, 2017.

The Commission entered orders granting the petitions of NCSEA on August 7, 2017; EDF on September 5, 2017; NC WARN on September 15, 2017; CUCA on September 18, 2017; CIGFUR III, the Rate-Paying Neighbors, and NCFB on September 19, 2017; Sierra Club on September 27, 2017; Kroger on September 28, 2017; NCLM on October 4, 2017; ASU on October 19, 2017; Piedmont EMC, Rutherford EMC, Haywood EMC, and Blue Ridge EMC on October 20, 2017; the Commercial Group and Tech Customers on November 8, 2017; Concord and Kings Mountain on December 14, 2017; and Durham and NC Justice Center, et al. on January 11, 2018. The AGO's intervention is recognized pursuant to N.C. Gen. Stat. § 62-20. The Public Staff's intervention is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19.

On September 19, 2017, the Commission issued its Order Establishing General Rate Case and Suspending Rates. On October 13, 2017, the Commission issued its Order Scheduling Investigation and Hearings, Establishing Intervention and Testimony Due Dates and Discovery Guidelines, and Requiring Public Notice, and on October 20,

[2] DEBS provides various administrative and other services to DEC and other affiliated companies of Duke Energy. Tr. Vol. 4, p. 33.

2017, the Commission issued an Amended Order Scheduling Investigation and Hearings, Establishing Intervention and Testimony Due Dates and Discovery Guidelines, and Requiring Public Notice. On November 3, 2017, Sierra Club filed a Motion to Schedule Additional Public Hearing. On December 22, 2017, the Commission entered an Order Denying Sierra Club's Request for Public Hearing. On January 30, 2018, and February 23, 2018, the Commission issued orders revising the schedule for the expert witness hearing.

On July 10, 2017, the Commission issued an order consolidating DEC's request for deferral of coal ash costs in Docket No. E-7, Sub 1110 with this rate case. On October 18, 2017, the Commission issued an order consolidating the general rate proceeding in Docket No. E-7, Sub 1146 with DEC's request to implement a job retention rider in Docket No. E-7, Sub 1152 and DEC's petition for approval to cancel the William States Lee III Nuclear Station (Lee Nuclear Project or Lee Nuclear) in Docket No. E-7, Sub 819.

DEC filed the supplemental testimony and exhibits of Company witness McManeus on December 15, 2017, and the second supplemental testimony and exhibits of Company witness McManeus on January 16, 2018.

On January 18, 2018, the AGO filed a motion for extension of time for intervenors to file testimony and exhibits. On January 20, 2018, the Commission entered an order granting an extension of time for intervenors to file testimony and exhibits until January 23, 2018, and for DEC to file rebuttal testimony and exhibits until February 6, 2018. On January 18, 2018, EDF filed the direct testimony of Paul J. Alvarez, President, Wired Group. On January 23, 2018, the Public Staff filed the direct testimony and exhibits of Jack L. Floyd, Engineer with the Electric Division of the Public Staff; L. Bernard Garrett, Secretary/Treasurer, Garrett and Moore, Inc.; John R. Hinton, Director of the Economic Research Division of the Public Staff; Michelle M. Boswell, Staff Accountant with the Accounting Division of the Public Staff; Charles Junis, Engineer with the Water, Sewer, and Communications Division of the Public Staff; Jay Lucas, Engineer with the Electric Division of the Public Staff; Michael C. Maness, Director of the Accounting Division of the Public Staff; Roxie McCullar, Consultant, William Dunkel and Associates; James S. McLawhorn, Director of Electric Division of the Public Staff; Dustin Ray Metz, Engineer with the Electric Division of the Public Staff; Vance F. Moore, President, Garrett and Moore, Inc.; David C. Parcell, Principal and Senior Economist, Technical Associates, Inc.; Scott J. Saillor, Engineer with the Electric Division of the Public Staff; and Tommy C. Williamson, Jr., Engineer with the Electric Division of the Public Staff. On January 23, 2018, the AGO filed the direct testimony and exhibits of J. Randall Woolridge, Professor of Finance, Pennsylvania State University, and Dan J. Wittliff, Managing Director of Environmental Services, GDS Associates, Inc.

On January 23, 2017, CUCA filed the direct testimony and exhibits of Kevin W. O'Donnell, President, Nova Energy Consultants, Inc.; the Tech Customers filed the direct testimony and exhibits of Kurt G. Strunk, Director of National Economic Research Associates (NERA), and Edward D. Kee, Expert Affiliate, NERA Economic Consulting;

Kroger filed the direct testimony and exhibits of Kevin C. Higgins, Principal, Energy Strategies, LLC; NC Justice Center, et al. filed the direct testimony and exhibits of Satana Deberry, Executive Director, North Carolina Housing Coalition, John Howat, Senior Policy Analyst, National Consumer Law Center, and Jonathan F. Wallach, Vice President, Resource Insight, Inc.; Sierra Club filed the direct testimony and exhibits of Ezra D. Hausman, Ph.D., Consultant, Ezra Hausman Consulting, and Mark Quarles, Principal Scientist and Owner, Global Environmental, LLC; NCLM filed the direct testimony and exhibits of Brian W. Coughlan, President, Utility Management Services, Inc., F. Hardin Watkins, Jr., City Manager, City of Burlington, Maria S. Hunnicutt, General Manager, Broad River Water Authority, and Adam Fischer, Transportation Director, City of Greensboro; CIGFUR III filed the direct testimony and exhibits of Nicholas Phillips, Jr., Managing Principal, Brubaker & Associates, Inc.; and NCSEA filed the direct testimony and exhibits of Justin R. Barnes, Director of Research, EQ Research LLC, Caroline Golin, Southeast Regulatory Director, Vote Solar, and Michael E. Murray, President, Mission:data Coalition. On January 24, 2018, the Commercial Group filed the direct testimony and exhibits of Steve W. Chriss, Director, Energy Strategy and Analysis, Wal-Mart Stores, Inc. and Wayne Rosa, Energy and Maintenance Manager, Food Lion, LLC.

On January 25, 2018, DEC filed a motion to strike the direct testimony of NCSEA witness Murray. On February 1, 2018, NCSEA filed its response in opposition to DEC's motion to strike the testimony of witness Murray. The Commission issued an order on February 6, 2018, denying DEC's motion to strike the testimony of witness Murray.

On January 26, 2018, DEC filed a motion to strike the direct testimony of EDF witness Alvarez and a motion to strike the direct testimony of NC Justice Center, et al. witness Howat. On January 30, 2018, EDF filed its response in opposition to DEC's motion to strike the testimony of witness Alvarez. On February 2, 2018, NC Justice Center, et al. filed its response in opposition to DEC's motion to strike the testimony of witness Howat. On February 6, 2018, the Commission issued an order denying DEC's motion to strike the testimony of witness Alvarez and an order granting DEC's motion to strike the testimony of witness Howat. The Commission struck from the record NC Justice Center, et al. witness Howat's direct testimony from page 4, line 21, to page 5, line 7, from page 21, line 3, to page 32, line 5, and page 32, lines 9 to 19.

On February 6, 2018, DEC filed the rebuttal testimony and exhibits of Company witnesses: McManeus; Cowling; De May; Diaz; Doss; Fallon; Fountain; Hager; Hevert; Hunsicker; Kerin; Jeffrey T. Kopp, Manager, Burns & McDonnell Engineering Company, Inc.; McGee; Miller; Pirro; Schneider; Thomas Silinski, Vice President, Total Rewards and Human Resource Operations, DEBS; Simpson; John J. Spanos, Senior Vice President, Gannett Fleming Valuation and Rate Consultants, LLC; James Wells, Vice President, Environmental Health and Safety, Coal Combustion Products, DEBS; and Wright.

On February 20, 2018, the Public Staff filed supplemental testimony and exhibits of witnesses Boswell, Hinton, Junis, Maness, Moore, and Saillor. The Public Staff filed the second supplemental testimony and exhibits of witnesses Hinton and Boswell on

March 19, 2018. On March 9, 2018, the AGO filed the supplemental testimony of witness Woolridge. On March 20, 2018, the Tech Customers filed the supplemental testimony of Dr. Sharon Brown-Hruska, Managing Director, NERA, and witness Strunk.

On February 28, 2018, DEC and the Public Staff entered into and filed an Agreement and Stipulation of Partial Settlement (the Stipulation). The Stipulation resolves some of the issues between the two parties in this docket. However, several unresolved issues still exist, including but not limited to: (1) the treatment of the Company's coal combustion residuals costs; (2) the amount of the Basic Facilities Charge (BFC); (3) whether it is appropriate to allow a return on the unamortized balance related to the Company's Lee Nuclear plant during the amortization period; (4) the status of the Company's Nuclear Decommissioning Trust Fund (NDTF) and the Public Staff's proposal to adjust nuclear decommissioning expense; (5) the manner in which the Federal Tax Cuts and Jobs Act (Tax Act) should be addressed in this case; (6) whether the Grid Reliability and Resiliency Rider (Grid Rider) should be adopted in this proceeding, and if so, which costs would be included in the Grid Rider and the structure of a Grid Rider; and (7) two discrete issues related to the Company's proposal for a Jobs Retention Rider (JRR), further described herein (collectively, the Unresolved Issues).

On March 1, 2018, the Public Staff filed settlement supporting testimony and exhibits of witnesses Boswell, Maness, and Parcell, and DEC filed settlement supporting testimony and exhibits of witnesses De May, Fountain, Hevert, McManeus, and Pirro. On February 28, 2018, DEC entered into and filed a Partial Settlement Agreement with NCLM, Concord, and Kings Mountain related to street lighting issues. On March 2, 2018, DEC entered into and filed an Amended Partial Settlement Agreement with NCLM, Concord, Kings Mountain, and Durham, which modified the original settlement related to certain street lighting issues and added Durham as a party (the Lighting Settlement).

The three public witness hearings were held as scheduled. The following public witnesses appeared and testified:

Franklin: David Watters, Selma Sparks, The Honorable Kevin Corbin, Donn Erickson, Henry Horton, Fred Crawford, Virginia Bugash, Avram Friedman, Debra Lawley, Bob Boyd, Tamara Zwinak, Margaret Crownover, Janet Wilde, and Robert Smith

Greensboro: Sharon Goodson, John Carter, Aaron Martin, Clarence Wright, Ruth Martin, Deborah Graham, Hester Petty, David Sevier, Joan Bass, John Merrell, Marta Concepcion, Gayle Tuch, August Preschle, Claudia Lange, Harry Phillips, Rexanne Bishop, Tim Stevenson, Taina Diaz-Reyes, Debbie Smith, Doug Ruder, Gladys Ellison, John Robins, Henry Fansler, Rachel Kriegsman, David Freeman, John Motsinger, Lib Hutchby, and Megan Longstreet

Charlotte: Brian Kasher, Mary Anne Hitt, Yvette Baker, Melvina Williams, Lilly Taylor, Steve English, Nancy Nicholson, Sally Kneidel, Callina Satterfield, Amy Brown, Roger Hollis, Kent Crawford, Ritchie Johnson, Ernie McLaney, Willie Dawson, Pat Moore, Beth Henry, James Sprouse, Charles Talley, June Blotnick, Charles King, Meg Houlihan, Steve Copulsky, Elaine Jones, Christian Cano, Joel Segal, Kathy Sparrow, Rick Lauer, Nicholas Rose, Wells Eddleman, Walker Spruill, Violet Mitchell, and Holliday Adams

The matter came on for expert witness testimony on March 5, 2018. DEC presented the testimony of witnesses De May, Hevert, Fountain, McManeus, Spanos, Kopp, Fallon, Diaz, Doss, Wright, Kerin, Simpson, Hunsicker, Schneider, Pirro, Hager, and Wells. The Public Staff presented the testimony of witnesses McLawhorn, Moore, Garrett, Maness, Williamson, Hinton, Metz, and Floyd. The AGO presented the testimony of witnesses Woolridge and Wittliff. The Sierra Club presented the testimony of witness Quarles. NCSEA presented the testimony of witnesses Golin and Barnes. CUCA presented the testimony of witness O'Donnell. NCLM presented the testimony of witness Coughlan. Tech Customers presented the testimony of witness Kee. The pre-filed testimony of those witnesses who testified at the expert witness hearing, as well as all other witnesses filing testimony in this docket, was copied into the record as if given orally from the stand.

DEC filed various late-filed exhibits and responses to Commission requests on the following dates: March 28, 2018, March 29, 2018, April 2, 2018, April 3, 2018, April 4, 2018, April 5, 2018, April 6, 2018, April 19, 2018 and April 23, 2018.

On April 16, 2018, the AGO filed a Response to Commission Request and Motion to Admit AGO Late-Filed Exhibit, which was granted on April 24, 2018.

The parties submitted briefs and/or proposed orders on April 27, 2018.

On June 1, 2018, DEC filed a Stipulation and Settlement Agreement between DEC and the EDF, Sierra Club, and NCSEA and a Stipulation and Settlement Agreement between DEC and the Commercial Group relating to the Power Forward Carolinas program and the Grid Rider proposed by DEC in this case (collectively, the Grid Rider Settlement). In its cover letter transmitting the stipulations and settlement agreements, DEC indicated that in order to mitigate the impact of a rate adjustment on low income customers and to support job training, DEC will make a shareholder-funded contribution totaling $4 million to the following programs: $1.5 million to the Helping Home Fund program for income qualified customers, $1.5 million to the Share the Warmth energy assistance fund, and $1 million to the Duke Energy/Piedmont Natural Gas Community College Apprenticeship Grant Program.

Between June 1, 2018, and June15, 2018, the following parties filed opposition and/or concerns regarding the Grid Rider Settlement: NC Justice Center, NC WARN, Public Staff, CUCA, AGO, CIGFUR III, and Tech Customers.

On June 8, 2018, the North Carolina Clean Energy Business Alliance (NCCEBA) filed a Petition to Intervene which was denied as out-of-time on June 20, 2018.

Based upon consideration of the pleadings, testimony, and exhibits received into evidence at the hearings, the Stipulation, the Lighting Settlement, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

Jurisdiction

1. DEC is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of this Commission. The Company is engaged in the business of generating, transmitting, distributing, and selling electric power to the public in the central and western portions of North Carolina and western South Carolina. DEC is a wholly-owned subsidiary of Duke Energy, and its office and principal place of business is located in Charlotte, North Carolina.

2. The Commission has jurisdiction over the rates and charges, rate schedules, classifications, and practices of public utilities operating in North Carolina, including DEC, under Chapter 62 of the General Statutes of North Carolina.

3. DEC is lawfully before the Commission based upon its Application for a general increase in its retail rates pursuant to N.C. Gen. Stat. §§ 62-133 and 62-134 and Commission Rule R1-17.

4. The appropriate test period for use in this proceeding is the 12 months ended December 31, 2016, adjusted for certain known changes in revenue, expenses, and rate base through December 31, 2017, and the costs for the W. S. Lee Combined Cycle (Lee CC) updated through February 28, 2018.

The Application

5. DEC, by its Application and initial direct testimony and exhibits, originally sought a net increase of approximately $611 million, or 12.8%, in its annual electric sales revenues from its North Carolina retail electric operations, including a rate of return on common equity of 10.75% and a capital structure consisting of 47% debt and 53% equity. The Company also requested a Grid Rider to recover an additional $35.2 million, which has the effect of an additional 0.8% increase. DEC filed supplemental filings and testimony after its initial Application and the effect of the Company's supplemental filings was to change its proposed annual revenue requirement increase to $700,645,000.

6. DEC submitted evidence in this case with respect to revenue, expenses, and rate base using a test period consisting of the 12 months ended December 31, 2016, adjusted for certain known changes in revenue, expenses, and rate base.

The Stipulation

7. On February 28, 2018, DEC and the Public Staff (the Stipulating Parties) entered into and filed the Stipulation resolving some of the issues in this proceeding between the two parties. Those issues that were not resolved by the Stipulation are referred to herein as the "Unresolved Issues."

8. The revenue requirement effect of the Stipulation is shown in Boswell Third Supplemental and Stipulation Exhibit 1 Corrected[3] and Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues,[4] which provide sufficient support for the annual revenue required on the issues agreed to in the Stipulation.

9. The Stipulation is the product of the give-and-take in settlement negotiations between the Stipulating Parties, is material evidence in this proceeding, and is entitled to be given appropriate weight in this proceeding, along with other evidence from the Company and intervenor parties, and along with statements from customers of the Company as well as testimony of public witnesses concerning the Company's Application.

10. The Stipulation resolves only some of the disputed issues between the Stipulating Parties. The Unresolved Issues include the cost recovery of the Company's CCR costs, the recovery amortization period and return during the amortization period, allocation issues associated with CCR costs, the amount of ongoing CCR costs to be included in rates, or whether certain CCR costs are recoverable under N.C. Gen. Stat. § 62-133.2. Further Unresolved Issues include amount of project development costs to be recovered for the Lee Nuclear Plant and whether the unamortized balance should earn a return, whether the Nuclear Decommissioning Trust Fund is overfunded, the amount of the Basic Facilities Charge, Power Forward and the Grid Rider, the methodology for calculating customer usage, recovery of costs for AMI, issues surrounding the implementation of the Federal Tax Cuts and Jobs Act (the Tax Act), several issues related to the JRR, and the proper contingency factor related to depreciation. The Unresolved Issues are resolved by the Commission and are addressed later in this Order.

[3] On April 19, 2018, the Public Staff filed Boswell Third Supplemental and Stipulation Exhibit 1 Corrected, which: (1) corrects the Lee CC addition to plant in service; (2) corrects the Lee CC deferral calculation; (3) updates the Grid Rider amount; and (d) reflects the Company's position on each filed issue.

[4] On April 19, 2018, the Company filed Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues and Revised McManeus Workpapers – Updated for Post-Hearing Issues, which reflect the following updates: (1) updates to the salaries and wages adjustment to reflect the Company and Public Staff's resolution on how to quantify the agreement reached in the Stipulation; (2) updates to the Lee CC plant and expense related items to reflect final costing information for inclusion in this proceeding, including updates to plant investment, related deferred income taxes, depreciation, materials and supplies, and the deferral of those costs between the plant's operation date and the date rates are expected to become effective; and (3) updates to reflect the cash working capital amounts and income taxes that are affected by the adjustments made to salaries and wages, and Lee CC.

Capital Structure, Cost of Capital, and Overall Rate of Return

11. The Stipulating Parties agree that the revenue requirement approved in this Order is intended to provide DEC, through sound management, the opportunity to earn an overall rate of return of 7.35%. This overall rate of return is derived from applying an embedded cost of debt of 4.59% and a rate of return on equity of 9.9% to a capital structure consisting of 48% long-term debt and 52% members' equity. The Stipulation is material evidence entitled to appropriate weight in determining DEC's overall rate of return, cost of debt, rate of return on equity, and capital structure.

12. A 9.9% rate of return on equity for DEC is just and reasonable in this general rate case.

13. A 52% equity and 48% debt ratio is a reasonable capital structure for DEC in this case.

14. A 4.59% cost of debt for DEC is reasonable for the purposes of this case.

15. Notwithstanding the decrease in rates ordered herein, the rates approved in this case, which includes the approved rate of return on equity and capital structure, will be difficult for some of DEC's customers to pay, in particular DEC's low-income customers.

16. Continuous safe, adequate, and reliable electric service by DEC is essential to the support of businesses, jobs, hospitals, government services, and the maintenance of a healthy environment.

17. The rate of return on equity and capital structure approved by the Commission appropriately balances the benefits received by DEC's customers from DEC's provision of safe, adequate, and reliable electric service in support of businesses, jobs, hospitals, government services, and the maintenance of a healthy environment with the difficulties that some of DEC's customers will experience in paying the Company's rates.

18. The 9.9% rate of return on equity and the 52% equity financing approved by the Commission in this case result in a cost of capital that is as low as reasonably possible. They appropriately balance DEC's need to obtain equity financing and to maintain a strong credit rating with its customers' need to pay the lowest possible rates.

19. The authorized levels of overall rate of return and rate of return on equity set forth above are supported by competent, material, and substantial record evidence, are consistent with the requirements of N.C. Gen. Stat. § 62-133, and are fair to DEC's customers generally and in light of the impact of changing economic conditions.

Adjustments to Cost of Service

20. The agreed-upon accounting adjustments outlined in Boswell Third Supplemental and Stipulation Exhibit 1 Corrected and Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues are just and reasonable to all parties in light of all the evidence presented.

State EDIT

21. The Stipulation provides that the state excess deferred income taxes (State EDIT) the Company collected pursuant to the Commission's May 13, 2014 Order in Docket No. M-100, Sub 138 should be returned to customers through a levelized rider that will expire at the end of a four-year period. The Stipulating Parties provide that the appropriate level of State EDIT to be refunded to customers is $60,102,000 annually for the four years following the effective date of the rates approved in this proceeding. The four-year State EDIT rider as set forth in Section III.B of the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Customer Connect

22. The Stipulation provides for the removal of the Company's incremental operating expenses for the Customer Connect project as recommended by the Public Staff. In accordance with Section III.C of the Stipulation, the Company is authorized to establish a regulatory asset to defer and amortize expenses associated with the Customer Connect project. As set forth in the Stipulation, the Company is allowed to accrue and recover Allowance for Funds Used During Construction (AFUDC) on the regulatory asset until the DEC Core Meter-to-Cash release (Releases 5-8) of the Customer Connect project goes into service or January 1, 2023, whichever is sooner, at which time a 15-year amortization shall begin. The parties agreed in the Stipulation that in order to provide the Commission and other interested parties with information concerning the status of development, spending, and the accomplishments to date, the Stipulating Parties will develop the reporting format and the content of that report within 90 days of this Order, with the reports to be filed in this docket for the next five years by December 31 of each year or until Customer Connect is fully implemented, whichever is later. This provision of the Stipulation is just and reasonable to all parties in light of all of the evidence presented. However, in order to allow sufficient time for the Company to complete its financial close process for the fiscal year, a critical step in obtaining the financial data needed to accurately report annual spend on Customer Connect, the Commission finds that the annual report required shall be filed by February 15, for the next five years.

Lee Combined Cycle

23. At the time the Stipulation was filed on February 28, 2018, the Company's Lee CC plant was almost complete, but not anticipated to come online until March 2018. Pursuant to the Stipulation, DEC withdrew its adjustment to include incremental operation

and maintenance (O&M) expenses for the Lee CC, and the Public Staff withdrew its displacement adjustment for the Lee CC; the Stipulating Parties therefore agreed that the appropriate level of ongoing O&M expense to be included in rates is $0. The Stipulating Parties further agreed that the appropriate amortization period for the deferred expenses is four years. The Stipulation additionally requires that the Company provide the Public Staff and the Commission with the final cost amounts to be included in this proceeding for determining the impact of the Lee CC on the overall revenue adjustment approved by the Commission by March 23, 2018. The Stipulation provides that the Public Staff utilize these amounts to work with the Company to file with the Commission, on or before April 6, 2018, the Stipulating Parties' final recommendation with regard to the Lee CC-related revenue requirement, including Lee CC deferred costs, using the methodology recommended by the Public Staff in this proceeding, excluding the appropriate amortization period for Lee CC deferred costs. The Stipulating Parties further agreed that it would be appropriate to hold the record open until April 22, 2018, for the sole purpose of allowing the Company to file an affidavit indicating that the plant has closed to service for operational and accounting purposes and that it is used and useful for the benefit of customers. This provision of the Stipulation is just and reasonable to all parties in light of all of the evidence presented.

24. In accordance with Section III.L of the Stipulation, on March 23, 2018, DEC provided the Public Staff and the Commission with the final cost amounts to be included in this proceeding for determining the impact of the Lee CC on the overall revenue adjustment approved by the Commission. On April 10, 2018, the Public Staff filed its updated recommendations regarding Lee CC plant and expense-related items, as shown in Boswell Third Supplemental and Stipulation Exhibit 1. Also on April 10, 2018, the Company filed the Affidavit of Joseph A. Miller, Jr., indicating that as of April 5, 2018, the Lee CC plant closed to service for operational and accounting purposes. On April 19, 2018, DEC filed Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues, which, among other things, reflects updates to the Lee CC plant and expense-related items to reflect final cost information for inclusion in this proceeding, including updates to plant investment, related deferred income taxes, depreciation, materials and supplies, and the deferral of those costs between the plant's operation date and the date rates are expected to become effective. Also on April 19, 2018, the Public Staff filed Boswell Third Supplemental and Stipulation Exhibit 1 Corrected, which, among other things, corrects the Lee CC addition to plant in service and corrects the Lee CC deferral calculation. The Lee CC-related revenue requirement updated in the final recommendation of the Stipulating Parties, as shown in Boswell Third Supplemental and Stipulation Exhibit 1 Corrected and Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues is just and reasonable.

Requested Coal Combustion Residuals (CCR) Fuel Costs

25. Given the Commission's Findings of Fact Nos. 57-59 and associated conclusions in its Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase entered on February 23, 2018, in Docket No. E-2, Sub 1142 (2018 DEP Rate Order), in Section III.P of the Stipulation DEC withdrew its request to recover

certain coal combustion residuals (CCR) costs through the fuel adjustment clause related to the excavation and movement of CCRs from the Riverbend Plant in Gaston County, North Carolina to the Brickhaven facility in Chatham County, North Carolina. The Stipulation also provides that the recovery of these costs be left in the Company's deferred CCR balance for consideration of recovery in the Company's base rates. These costs should be excluded from recovery through the fuel adjustment clause, and should be included in the Company's deferred CCR balance for consideration of recovery in the Company's base rates. This provision of the Stipulation is just and reasonable to all parties in light of all of the evidence presented.

Base Fuel Factor

26. Section IV.B of the Stipulation provides that the base fuel and fuel-related cost factors, by customer class, will be as set forth in the following table (amounts are cents per kilowatt-hour (kWh), excluding regulatory fee):

	Residential	General Service/Lighting	Industrial
Total Base Fuel (matches approved fuel rate effective September 1, 2017 in Docket No. E-7, Sub 1129)	1.7828	1.9163	2.0207

The base fuel and fuel-related cost factors set forth in Section IV.B of the Stipulation are just and reasonable to all parties in light of all the evidence presented.

Coal Inventory

27. As set forth in Paragraph III.I. of the Stipulation, DEC shall reduce the amount of coal inventory included in working capital. An increment rider shall be established, effective on the same date as the new base rates approved in this Order, and continuing until inventory levels reach a 35-day supply, to allow the Company to recover the additional costs of carrying coal inventory in excess of a 35-day supply (priced at $73.23 per ton). This rider shall terminate on the earlier of: (a) May 31, 2020, or (b) the last day of the month in which the Company's actual coal inventory levels return to a 35-day supply on a sustained basis, as defined in the Stipulation. The reduction to coal inventory included in working capital and the establishment of the increment rider, as set forth in the Stipulation, is just and reasonable to all parties in light of all the evidence presented.

Cost of Service Allocation Methodology

28. The Stipulation provides for the use of the Summer Coincident Peak (SCP) methodology for cost allocation between jurisdictions and among customer classes in this case. The Company may continue to use the SCP methodology for allocation between jurisdictions and among customer classes under the provisions of the Stipulation. The

provisions of the Stipulation regarding cost of service methodology are just and reasonable to all parties in light of all the evidence presented.

Lead-Lag Study

29. The Stipulation provides that DEC shall prepare and file a lead-lag study in its next general rate case. This provision of the Stipulation is just and reasonable.

Rate Design

30. Except for the amount of the Basic Facilities Charge which is discussed later in this Order, the Stipulation provides for the implementation of the rate design proposed by Company witness Pirro in his direct testimony, as set out in Section IV.E of the Stipulation. The Stipulating Parties also agreed that, to the extent possible, the Company shall assign the approved revenue requirement consistent with the principles regarding revenue apportionment described in the testimony of Public Staff witness Floyd. Moreover, the Company entered into the Lighting Settlement with NCLM, Concord, Kings Mountain, and Durham, which resolved all outdoor lighting issues raised by intervenors in this docket. Based on all of the evidence presented in this proceeding, the rate design provisions in Section IV.E of the Stipulation and the Lighting Settlement are just and reasonable to all parties in light of all the evidence presented. It is appropriate for the Company to implement the rate design proposed by witnesses Pirro and Cowling, consistent with the provisions in Section IV.E of the Stipulation and the Lighting Settlement.

Vegetation Management, Quality of Service, and Service Regulations

31. DEC's and the Public Staff's agreement relating to vegetation management, as set forth in Section III.A of the Stipulation, is just and reasonable to all parties in light of all the evidence presented.

32. The overall quality of electric service provided by DEC is adequate.

33. The proposed amendments to DEC's Service Regulations are just and reasonable, serve the public interest, and should be approved.

Acceptance of Stipulation

34. The Stipulation and the Lighting Settlement will provide DEC and its retail ratepayers just and reasonable rates when combined with the rate effects of the Commission's decisions regarding the contested issues in this proceeding.

35. The provisions of the Stipulation and the Lighting Settlement are just and reasonable to all parties to this proceeding and serve the public interest. Therefore, the Stipulation and the Lighting Settlement should be approved in their entirety.

Basic Facilities Charge (BFC)

36. The Company shall increase the monthly BFC for the residential rate class (Schedules RS, RT, RE, ES, and ESA) to $14.00. The increase in the BFC for the residential rate class schedules is just and reasonable. The BFC for other rate schedules shall be left unchanged from the current rates.

Customer Usage

37. The methodology for calculating customer usage set forth in the testimony of Public Staff witness Saillor, with the adjustments proposed by Company witness Pirro in his rebuttal testimony, is just and reasonable to all of the parties and should be employed by the Company in this case.

Advanced Metering Infrastructure (AMI)

38. DEC's AMI costs are reasonable and prudent, and DEC should be allowed to recover its AMI costs.

39. DEC should be required to design and propose new rate structures to capture the full benefits of AMI.

40. It is just and reasonable for DEC to recover the remaining book value of its Automated Meter Reading (AMR) meters over 15 years.

Customer Data

41. It is appropriate to address issues regarding access to customer usage data in Docket No. E-100, Sub 147.

Power Forward and the Grid Rider

42. DEC has failed to show that exceptional circumstances exist to justify the establishment of the Grid Rider for recovery of its Power Forward Carolinas (Power Forward) costs.

43. DEC has failed to show at this time that Power Forward costs qualify for deferral accounting treatment.

44. It is not necessary at this time for the Commission to open a separate proceeding to investigate grid modernization programs. For now, DEC should utilize existing proceedings, such as the Integrated Resource Planning and Smart Grid Technology Plan docket, to inform the Commission on and collaborate with stakeholders regarding grid modernization initiatives and the potential cost recovery mechanisms for such initiatives.

Lee Nuclear

45. In Docket No. E-7, Sub 819, which has been consolidated with this general rate case, the Company requests Commission approval of its decision to cancel the Lee Nuclear Project pursuant to N.C. Gen. Stat. § 62-110.7(d). The Company requests permission to move the adjusted balance of the Lee Nuclear Project development costs from construction work in progress (CWIP) Account 107 to regulatory asset Account 182.2 and to recover the project development costs in rates by amortizing such costs over a 12-year period. The Company also requests that the unamortized balance of such costs be included in rate base to recover a net-of-tax return on the unamortized balance.

46. DEC's actions in developing the Lee Nuclear Project have been reasonable and prudent and in compliance with the intent of the Commission's orders in Docket No. E-7, Sub 819.

47. DEC's decision to cancel the project is reasonable and prudent and in the public interest.

48. DEC's project development costs incurred for the Lee Nuclear Project, with the exception of costs relating to a Visitors' Center and the allowance for funds used during construction (AFUDC) for 2018, which were recommended for disallowance by the Public Staff and that the Company agreed to exclude,[5] are reasonable and prudent and should be amortized over a 12-year period, as requested by the Company.

49. It is not appropriate to permit the Company to earn a return on the unamortized balance of these project development costs during the amortization period, as requested. This rate treatment is consistent with Commission precedent and results in rates that are fair to both the Company and its ratepayers for the costs of the cancelled Lee Nuclear Project.

Nuclear Decommissioning Trust Fund (NDTF)

50. The Company proposes that the annual nuclear decommissioning expense be maintained at $0. The Public Staff has proposed that the Company's NDTF is overfunded and that the Company should be required to refund to customers $29 million per year. Because funds in the NDTF are to be used solely for decommissioning the Company's nuclear units, the Company is not permitted to withdraw funds from the NDTF for this purpose. Accordingly, the Public Staff proposes that the $29 million per year be refunded to customers through a "loan" from the Company's shareholders that would be repaid after decommissioning is complete.

[5] Excluding costs relating to the Visitors' Center and AFUDC for 2018, and extending the deferral period through April 2018, reduces the amount of the project development costs for Lee Nuclear from $353.2 million to $347.0 million. (See McManeus Rebuttal Ex. 3, p. 31, and Boswell Third Supplemental Ex. 1, p. 2 of 4.)

51. It is premature at this time to find that the NDTF is overfunded and that refunds should be required.

Depreciation

52. Use of a 10% contingency for future “unknowns” in the estimate of future terminal net salvage costs is reasonable in this case.

53. It is just and reasonable to use the escalation of terminal net salvage cost and the straight-line method of depreciation in determining escalation as performed in DEC’s Decommissioning Study.

54. Use of an interim net salvage percentage of zero for Accounts 342, 343, 344, 345, and 346 is reasonable in this case.

55. The depreciation rates proposed by DEC in this case, with the exception of the adjustments discussed above, as filed by the Company as Doss Exhibits 3 and 4, are just and reasonable and should be approved.

Tax Changes

56. In this docket, the Commission has been presented with two proposals for the implementation of the Tax Act, one by the Company and one by the Public Staff. The Company proposal would:

(a) Implement an immediate reduction in its revenue requirements to reflect collection of federal corporate income tax at the 21% rate instead of the 35% rate.

(b) Implement flow back of federal excess deferred income taxes (Federal EDIT) to customers, as follows:

(i) For Federal EDIT protected under Internal Revenue Service (IRS) normalization rules, in accordance with those rules;

(ii) For Federal EDIT not protected by normalization rules, but related to property, plant and equipment (PP&E), over a 20-year period; and

(iii) For Federal EDIT not protected by normalization rules, but not related to PP&E, through a five-year rider (federal unprotected non-PP&E rider).

(c) As a cash flow mitigation measure, increase the revenue requirement by $200 million, through any of a variety of mechanisms.

57. The Public Staff proposal would implement the Tax Act by implementing the same immediate reduction in revenue requirements based upon the tax rate reduction, implement the IRS-prescribed flow back of protected Federal EDIT, and implement the flowback of all unprotected Federal EDIT through a five-year rider. The Public Staff proposal would not provide any cash flow mitigation measures.

58. It is appropriate to reflect the 21% Federal corporate income tax rate specified in the Tax Act in DEC's revenue requirement in this proceeding. It is further appropriate to deny DEC's proposed $200 million cash flow mitigation measure and to require DEC to maintain all EDIT resulting from the Tax Act in a regulatory liability account pending flow back with interest reflected at the overall weighted cost of capital approved in this case of 7.35% in three years or in DEC's next general rate case proceeding, whichever is sooner.

Job Retention Rider (JRR)

59. The Company's proposed JRR is intended to allow the Company to prevent the loss of North Carolina jobs and the customer's related load.

60. Because gas pipelines are fixed investments that are not easily relocated, extending the benefits of a JRR to gas pipeline companies would not prevent the loss of North Carolina jobs. Companies involved in the "transportation or preservation of a raw material of a finished product" should not be eligible to participate in a JRR.

61. The Job Retention Tariff (JRT) Guidelines state that this tariff is intended to be temporary and to establish a maximum effective time of five years or a cap of five years. However, under the current economic circumstances, a shorter period of time, possibly one or two years, may achieve the intended result. Thus, a one-year pilot with the option of a renewal for a second year is an appropriate time frame for the current JRR.

62. The JRR proposed by the Company, as modified by the Stipulation and this Order, is not unduly discriminatory and is in the public interest.

63. Ratepayers, the Company, and its shareholders all benefit from the retention of North Carolina jobs and the load related to those jobs.

64. The Company's recovery of the JRR revenue credits should be reduced by $4.5 million each year the JRR is in effect, if more than one year, to recognize the benefit to shareholders of the JRR.

CCR Cost Deferral

65. In Docket Nos. E-2, Sub 1103 and E-7, Sub 1110, DEP and DEC jointly filed a request that the Commission issue an order authorizing them to defer in a regulatory asset account certain costs incurred in connection with compliance with federal and state environmental requirements regarding CCRs. By Order dated July 10, 2017, the Commission consolidated DEC's request with the present general rate case. DEC

and the Public Staff supported the deferral in their testimony in this docket. The deferral request is reasonable and appropriate.

66. DEC expects to incur substantial costs related to CCRs in future years. It is just and reasonable to allow deferral of those costs, with a return at the net-of-tax overall cost of capital approved in this Order during the deferral period. Ratemaking treatment of such costs will be addressed in future rate cases.

67. It is reasonable and appropriate to add a return based on the net-of-tax overall cost of capital approved in DEC's last general rate case to the amount of deferred coal ash costs, as approved in this proceeding, for the period through the effective date of rates approved in this proceeding. The federal tax rate appropriate to use for the 2018 portion of the carrying costs is 21%.

68. It is reasonable and appropriate to use a mid-month cash flow convention for calculation of the return on the principal amount of deferred CCR expenditures. Compounding should take place at the beginning of January of each year.

Recovery of CCR Costs

69. Since its last rate case, DEC has become subject to new legal requirements relating to its management of coal ash. These new legal requirements mandate the closure of the coal ash basins at all of the Company's coal-fired power plants. Since its last rate case, DEC has incurred significant costs to comply with these new legal requirements.

70. On a North Carolina retail jurisdiction basis, the actual coal ash basin closure costs DEC has incurred during the period from January 1, 2015, through December 31, 2017, amount to $545.7 million. DEC is eligible to recover these coal ash basin closure costs. The actual coal ash basin costs incurred by DEC are known and measurable, reasonable and prudent, and, to the extent capital in nature, used and useful in the provision of service to the Company's customers. Further, DEC proposes that these costs be amortized over a five-year period, and that it earn a return on the unamortized balance. Under normal circumstances, the five-year amortization period proposed by the Company is appropriate and reasonable, and absent any management penalty, should be approved, and under normal circumstances the Commission within its discretion would allow the Company to earn a return on the unamortized balance.

71. Under the present facts, a management penalty in the approximate sum of $70 million is appropriate with respect to DEC's CCR remediation expenses accounted for in the earlier established Asset Retirement Obligation (ARO) with respect to costs incurred through the end of the test year, as adjusted. Through its use of available ratemaking mechanisms, the Commission is effectively implementing an estimated $70 million penalty by amortizing the $545.7 million over five years with a return on the unamortized balance and then reducing the resulting annual revenue requirement by $14 million for each of the five years.

72. DEC further proposes that it recover on an ongoing basis $201 million in annual coal ash basin closure costs, subject to true-up in future rate cases. The amount sought by the Company is based upon its actual test year (2016) spend. The Company's proposal to recover these ongoing costs as a portion of the rates approved in this Order is not appropriate. Rather, it is appropriate to allow DEC to record its January 1, 2018, and future CCR costs in a deferral account until its next general rate case.

Provisional CCR Cost Recovery

73. DEC's recovery of the CCR costs approved in this proceeding should not be through provisional rates.

CCR Allocation Guidelines

74. It is reasonable and appropriate to allocate all system-level CCR costs using a comprehensive allocation factor that allocates the costs to the entire DEC system.

75. It is reasonable and appropriate to allocate all CCR expenditures by an energy allocation factor, rather than a demand-related production plant allocation factor.

Insurance Litigation

76. It is appropriate, even if this case is appealable to a higher court, to require that DEC, within ten days of the resolution by settlement, dismissal, judgment, or otherwise of the litigation entitled Duke Energy Carolinas, LLC, et al. v. AG Insurance SA/NV, et al., Case No. 17 CVS 5594, Superior Court (Business Court), Mecklenburg County, North Carolina (Insurance Case), file a report with the Commission explaining the result and stating the amount of insurance proceeds to be received or recovered by DEC.

77. It is appropriate to require DEC to place all insurance proceeds it receives or recovers in the Insurance Case in a regulatory liability account and to hold such proceeds until the Commission enters an order directing DEC regarding the appropriate disbursement of the proceeds. The regulatory liability account should accrue a carrying charge at the net-of-tax overall rate of return authorized for DEC in this Order.

78. If meritorious concerns are raised by any party to this docket, or by the Commission, regarding the reasonableness of DEC's efforts to obtain an appropriate amount of recovery in the Insurance Case, it is appropriate to require DEC to bear the burden of proving that it exercised reasonable care and made reasonable efforts to obtain the maximum recovery in the Insurance Case.

Accounting for Deferred Costs

79. The Company is authorized to receive a specific amount of revenue for each of the several deferred costs approved by this Order. If DEC receives revenue for any

deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company should continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until its next general rate case.

Revenue Requirement

80. After giving effect to the approved Stipulation and the Commission's decision on contested issues, the annual revenue requirement for DEC will allow the Company a reasonable opportunity to earn the rate of return on its rate base that the Commission has found just and reasonable.

81. DEC should recalculate and file the annual revenue requirement with the Commission within ten days of the issuance of this Order, consistent with the findings and conclusions of this Order. The Company should work with the Public Staff to verify the accuracy of the filing. DEC should file schedules summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determinations in this proceeding.

82. The appropriate revenue requirement for the first four years should be reduced by the State EDIT Rider decrement of $60.102 million.

Just and Reasonable Rates

83. The base non-fuel and base fuel revenues approved herein are just and reasonable to the customers of DEC, DEC, and all parties to this proceeding, and serve the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-4

The evidence supporting these findings of fact and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding. These findings and conclusions are informational, procedural, and jurisdictional in nature, and are not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-6

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

On August 25, 2017, DEC filed its Application and initial direct testimony and exhibits, seeking a net increase of approximately $611 million, or 12.8%, in its annual electric sales revenues from its North Carolina retail electric operations. DEC is also proposing the Grid Rider to recover ongoing costs related to the modernization of the Company's electric grid, referred to as the Power Forward initiative. The Grid Rider brings the total impact of the Company's rate request in its Application to approximately

$647 million, a 13.6% increase across all customer classes. DEC submitted evidence in this case with respect to revenue, expenses, and rate base using a test period consisting of the 12 months ended December 31, 2016, updated for certain known and actual changes. After rebuttal and supplemental filings, the amount of the Company's requested revenue requirement increased to $700 million. The Company also requested a Grid Rider to recover $35.2 million in its first year.

Company witness Fountain testified that major generating plant projects, nuclear development work, grid improvements and modernization, additions and plant-related expenses, improvements to the Company's Customer Information System (CIS), and additional funding for vegetation management account for the majority of the total additional requested annual revenue requirement. Tr. Vol. 6, p. 163. The remainder of the requested rate adjustment is to recover costs related to environmental requirements associated with the mandated closure of ash basins and other ongoing operational costs, offset by certain regulatory liabilities and decreases in rate base. Id. In addition, DEC proposes a Grid Rider to recover ongoing costs related to the modernization of the Company's electric grid, referred to as the Power Forward Carolinas initiative (Power Forward). Id. at 162.

Witness Fountain detailed the Company's recent investments driving the Company's requested rate increase. Id. at 166-77. He described numerous nuclear, fossil, hydro, and solar projects that DEC has completed since its last rate case. Id. at 166. He explained that the Company has retired half of its older, less-efficient coal-fired generation units and is providing customers with increasingly clean energy from new gas-fueled generation, carbon-free nuclear plants, and utility scale solar projects. Id. at 165. For example, he described the Company's new Lee CC plant, which features state-of-the-art technology for increased efficiency and significantly reduced emissions. Id. at 167. In addition, the Company has added two solar facilities to DEC's generating mix and recently completed its relicensing effort for the Catawba-Wateree hydro project. Id.

Since the last rate case, the Company has also made investments designed to improve reliability and customer service. Id. at 168-69. Witness Fountain provided an overview of the Company's ongoing deployment of AMI, which will work in tandem with the Company's implementation of a new Customer Information System (CIS), called "Customer Connect," as well as the grid investments that make up Power Forward. Id. at 168-72. In addition, the Company has requested an increase in the pro forma for vegetation management to help improve grid reliability. Id. at 172-73.

Witness Fountain also outlined the coal ash basin closure costs the Company is seeking to recover in this case and emphasized that the Company is not seeking recovery of any costs incurred in response to the release of coal ash from the Dan River Steam Station in February 2014. Id. at 169-70, 173-77. The Company's Application also requests that the Commission permit DEC to cancel the Lee Nuclear Project as originally envisioned[6] and to recover costs for project development work completed for the project. Id. at 167-68. Finally, witness Fountain noted that the cost increases requested in this case are partially offset by the return of a deferred tax liability to customers. Id. at 170.

Witness Fountain explained that DEC's proposed rate adjustment means customers will still be paying lower rates today than they were in 1991 on an inflation-adjusted basis, and customers will continue to pay rates below the national average and competitive with other utilities in the region. Id. at 178. In addition, he pointed out that the typical residential customer's bill has declined from those approved in 2013 due, in part, to the Company prudently managing fuel costs and jointly dispatching the generation fleet to save $296 million. Id. at 177-78.

Witness Fountain also described the Company's ongoing efforts to mitigate customers' rate impacts. Id. at 180-85. He stated that to help customers reduce bills, the Company is continuing to expand and enhance its portfolio of DSM and EE programs. Id. at 182. According to witness Fountain, the Company offers customers more than a dozen energy-saving programs for every type of energy user and budget; EE programs currently save its customers in the Carolinas over 4.3 billion kWh annually, or over $357 million, which is about 5.4% of total retail kWh sales. Id. Combined, DEC's demand-side management (DSM) and Energy efficiency (EE) programs offset capacity requirements by the equivalent of over seven power plants. Id. Witness Fountain also described how the Company's Share the Warmth program helps low-income individuals and families cover home energy bills. Id. at 183. Since its inception, the program has provided approximately $26 million in assistance to DEC customers in North Carolina. Id. He explained that the Company allows customers a bill management option that allows them to spread out the impacts of seasonal fluctuations into 12 equal monthly payments. Id. at 184. The Company also offers payment arrangements to eligible customers who are having difficulty paying their entire bill by the due date. Id.

Witness Fountain indicated that the Company's most important objective is to continue providing safe, reliable, affordable, and increasingly clean electricity to its customers with high quality customer service, both today and in the future. Id. at 63. He concluded that the request for a rate increase is made to support investments that benefit DEC customers, and the Company strives to ensure that those investments are made in a cost-effective manner that retains the Company's level of service and competitive rates. Id. at 64.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-10

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the testimony of DEC witnesses Fountain, McManeus, Hevert, De May, and Pirro, the testimony of Public Staff witnesses Boswell, Maness, and Parcell, the Stipulation, and the Lighting Settlement.

[6] As discussed below, the Company seeks to retain the combined operating license (COL) granted by the Nuclear Regulatory Commission (NRC) in case circumstances change. Id. at 167.

On February 28, 2018, DEC and the Public Staff entered into and filed an Agreement and Stipulation of Partial Settlement, which resolves some of the issues in this proceeding between these two parties and provides for a revenue requirement increase of approximately $537,500,000 based on the settled issues. The Stipulation is based upon the same test period as the Company's Application.

Witness Fountain explained that the Stipulation would resolve many, but not all, of the revenue requirement issues between the Company and the Public Staff.[7] Tr. Vol. 6, p. 218. He outlined the key aspects of the Stipulation as follows:

Cost of Capital – The Stipulating Parties have agreed to a rate of return on equity of 9.9%, based upon a capital structure containing 52% equity and 48% debt as described by Company witnesses Hevert and De May. Id. The Company's debt cost rate shall be set at 4.59%. Id. at 218-19. The resulting weighted average rate of return is 7.35%. Id. at 219.

Distribution Vegetation Management – The Public Staff and DEC have agreed on the amount of distribution vegetation management expenses in an annual amount of $62.6 million on a total system basis. Id. This amount reflects rising contractor rates that are affecting the Company's costs in effectuating its trim cycles. Id. The Stipulation also includes commitments for certain catch up miles and a plan for transparent reporting so that the Commission and interested parties can be informed of the Company's vegetation management plans and expenditures. Id.

Lee CC – The Public Staff and the Company have agreed upon the appropriate level of ongoing O&M and deferred expenses for Lee CC. Id. The Stipulating Parties noted in the Stipulation that Lee CC is not anticipated to come online until March, and the Stipulation contains a plan to hold the record open solely for the purpose of verifying the amounts to be included in rates and confirmation that the plant is operational. Id.

Customer Connect Expenses – The Public Staff and the Company have resolved issues related to this important initiative such that the Company, if the Stipulation is approved, would be allowed to accrue and recover AFUDC on costs during the implementation period to be captured in a regulatory asset. Id. at 219-20.

[7] Witness Fountain identified the Unresolved Issues as follows: (1) the Company's request to recover its deferred coal ash costs and its ongoing environmental compliance costs necessary to safely close the Company's coal ash basins, as well as the method by which the Company should allocate coal ash costs; (2) whether it is appropriate to allow a return on the unamortized balance of costs relating to the Lee Nuclear Project during the amortization period; (3) the status of the Company's Nuclear Decommissioning Trust Fund and the Public Staff's proposal to adjust nuclear decommissioning expense; (4) the final update month to be used for ratemaking in this case; (5) the methodology for calculating customer usage through December 2017; (6) the manner in which the Federal Tax Cuts and Jobs Act should be addressed in this case; (7) the amount of annual depreciation expense and associated accumulated depreciation to be used for ratemaking in this case; (8) whether a Grid Rider should be adopted in this proceeding, and if so, which costs would be included in the Grid Rider and the structure of the Grid Rider; (9) the amount of the Basic Facilities Charge; and (10) any other revenue requirement or non-revenue requirement issues other than those issues specifically addressed in the Stipulation or agreed upon in the testimony of the Stipulating Parties. Tr. Vol. 6, pp. 223-24. As addressed by witness Pirro, the Company also has a different view than the Public Staff on certain items related to the Job Retention Rider. Id. at 224.

Other Adjustments – Revenue requirement adjustments were also agreed upon in the Stipulation for Aviation Expenses, Executive Compensation, Board of Directors, Lobbying, Sponsorships, and Donations for the U.S. Chamber of Commerce, Incentive Compensation, and Outside Services, as well as Duke Energy-Piedmont Natural Gas (Piedmont) merger costs to achieve, salaries and wages, and DEBS allocations. Id. at 220. The Stipulating Parties have also agreed to the implementation of a Coal Inventory Rider, and the Company has committed to study coal inventory levels and provide those results for review. Id. The Stipulating Parties also agreed on the return of the state excess deferred income taxes to customers through a four-year rider. Id.

Job Retention Rider – The Stipulating Parties have also agreed to resolve the Company's Job Retention Rider proposal, except for two remaining items to be decided upon by the Commission, as described in the Stipulation. Id.

Other Cost of Service and Rate Design Matters – The Stipulating Parties have also agreed upon rate design and cost of service study parameters as proposed by Company witnesses Pirro and Hager and Public Staff witness Floyd (aside from the amount of the Basic Facilities Charge, which is not resolved by the Stipulation). Id.

Recovery of CCR Costs Through the Fuel Adjustment Clause – The Company has agreed to withdraw its request to recover certain CCR costs through the fuel adjustment clause related to the excavation and movement of CCRs from the Company's Riverbend Plant to the Brickhaven Facility. Id. at 221. The effect of this provision of the Stipulation is that the Company and the Public Staff agree that these costs are left in DEC's deferred CCR balance for consideration of recovery in the Company's base rates. Id.

These accounting and ratemaking adjustments and the resulting revenue requirement effect of the Stipulation are shown in Boswell Third Supplemental and Stipulation Exhibit 1 Corrected and Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues, which provide sufficient support for the annual revenue required on the issues agreed to in the Stipulation. The Stipulating Parties' recommended revenue requirement increase after settled issues is approximately $541,117,000. However, the total adjustment in base rate revenues and the resulting average adjustment cannot be determined until the Commission resolves the Unresolved Issues.[8]

Witness Fountain testified that he attended public witness hearings held by the Commission in this matter and followed the consumer statement positions filed in this docket. Tr. Vol. 6, p. 221. He listened to customers' concerns about the impacts of any

[8] Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues shows DEC's revised requested increase incorporating the provisions of the Stipulation and the Company's position on the Unresolved Issues. The resulting proposed revenue requirement increase of the Company is $472,249,000. Boswell Third Supplemental and Stipulation Exhibit 1 Corrected shows the Public Staff's revised recommended change in revenue requirement incorporating the provisions of the Stipulation and a number of downward adjustments reflecting the Public Staff's position on the Unresolved Issues. The resulting proposed revenue requirement by the Public Staff is a decrease in the base rate revenue requirement of $101,230,000.

rate increase on their families and businesses and noted that the Company is very mindful of these concerns. Id. Witness Fountain believes that the concessions the Company made in the Stipulation fairly balance the needs of DEC's customers with the Company's need to recover substantial investments made in order to continue to comply with regulatory requirements and safely provide high quality electric service to its customers. Id. at 222. He added that the Company's rates need to be adjusted to reflect these investments. Id. Witness Fountain stated that given the size of the necessary capital and compliance expenditures the Company is facing, it is essential that DEC maintain its financial strength and credit quality, so that it will be in a position to finance these needs on reasonable terms for the benefit of its customers. Id. In his opinion, the Company has been able to strike that balance with the Stipulation. Id.

DEC witnesses McManeus, Hevert, De May, and Pirro also testified in support of the Stipulation. Witness De May testified that the Stipulation will support the Company's ability to achieve its financial objectives. Tr. Vol. 4, p. 89. Witness Hevert stated that although the stipulated rate of return on equity is somewhat below the lower bound of his recommended range, he understands the Company has determined that the terms of the Stipulation, in particular the stipulated return on equity and equity ratio, would be viewed by the rating agencies as constructive and equitable. Tr. Vol. 4 pp. 407-08. Witness Pirro testified concerning the effects of the partial settlement on DEC's proposed JRR and the Company's proposed reallocation of revenue resulting from the agreement among the Company, NCLM, and the Cities of Concord and Kings Mountain regarding lighting issues. Tr. Vol. 19, pp. 105-09. Witness McManeus presented exhibits showing the monetary effect of the various issues addressed in the Stipulation.

Public Staff witnesses Boswell, Maness, and Parcell also supported the Stipulation. Witness Boswell stated that the most important benefits of the Stipulation are an aggregate reduction in the increase of specific expense items requested in the Company's application and the avoidance of protracted litigation by the Stipulating Parties before the Commission and, possibly, the appellate courts. Tr. Vol. 26, p. 628. Witness Boswell also presented schedules showing the financial impact of the Stipulation. Witness Maness testified on the impact of the Stipulation on the unresolved CCR issues, and witness Parcell stated that the Stipulation reflects the result of good faith "give-and-take" and compromise-related negotiations among the parties. Tr. Vol. 26, p. 890.

As the Stipulation and the Lighting Settlement have not been adopted by all of the parties to this docket, its acceptance by the Commission is governed by the standards set out by the North Carolina Supreme Court in State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc., 348 N.C. 452, 500 S.E.2d 693 (1998) (CUCA I), and State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc., 351 N.C. 223, 524 S.E.2d 10 (2000) (CUCA II). In CUCA I the Supreme Court held that:

> [A] stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The

> Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding. The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes "its own independent conclusion" supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.

348 N.C. at 466, 500 S.E.2d at 703. However, as the Court made clear in CUCA II, the fact that fewer than all of the parties have adopted a settlement does not permit the Court to subject the Commission's order adopting the provisions of a nonunanimous stipulation to a "heightened standard" of review. 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court said that Commission approval of the provisions of a nonunanimous stipulation "requires only that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] ... satisf[y] the requirements of Chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties." Id. at 231-32, 524 S.E.2d at 16.

The Commission gives substantial weight to the testimony of the Company and Public Staff witnesses regarding the Stipulation and the Lighting Settlement, and finds and concludes that the Stipulation and the Lighting Settlement are the product of the "give-and-take" of the settlement negotiations between DEC and the Public Staff, as well as between DEC and NCLM, and the Cities of Concord, Kings Mountain, and Durham, in an effort to appropriately balance the Company's need for rate relief with the impact of such rate relief on customers. The Stipulation is, therefore, material evidence to be given appropriate weight in this proceeding.

Ample evidence exists in the record to support all of the provisions of the Stipulation, including those which have been contested by some intervenors other than the Stipulating Parties. Accordingly, the Commission is fully justified in adopting the Stipulation through the exercise of its own independent judgment, and finding and concluding through such independent judgment that the Stipulation "is just and reasonable to all parties in light of all the evidence presented." CUCA I, 348 N.C. at 466, 500 S.E.2d at 703. The Commission hereby adopts the Lighting Settlement in its entirety, and its conclusions as to the individual provisions are discussed in the rate design section of this order. The Commission hereby adopts the Stipulation in its entirety, and its conclusions as to the individual provisions of the Stipulation are set forth more fully below.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-19

The evidence supporting these findings of fact and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of the public witnesses, the testimony and exhibits of Company witnesses Hevert and De May, Public Staff witness Parcell, Commercial Group witnesses Chriss and Rosa, AGO witness Woolridge, CIGFUR III witness Phillips, Tech Customers witness Strunk and CUCA witness O'Donnell, and the entire record of this proceeding.

Rate of Return on Equity

In its Application, the Company requested approval for its rates to be set using a rate of return on equity of 10.75%. The Stipulation provides for a rate of return on equity of 9.9%, which is a decrease from the 10.2% level authorized by the Commission in the Company's last rate case. For the reasons set forth herein, the Commission finds that a rate of return on equity of 9.9% is just and reasonable.

Rate of return on equity, also referred to as the cost of equity capital, is often one of the most contentious issues to be addressed in a rate case, even in a case such as this one in which a Stipulation between the utility and the consumer advocate has been reached. In the absence of a settlement agreed to by all parties, the Commission must still exercise its independent judgment and arrive at its own independent conclusion as to all matters at issue, including the rate of return on equity. See, e.g., CUCA I, 348 N.C. at 466, 500 S.E.2d at 707. In order to reach an appropriate independent conclusion regarding the rate of return on equity, the Commission should evaluate the available evidence, particularly that presented by conflicting expert witnesses. State ex rel. Utils. Comm'n v. Cooper, 366 N.C. 484, 739 S.E.2d 541, 546-47 (2013) (Cooper I). In this case, the expert witness evidence relating to the Company's cost of equity capital was presented by Company witness Hevert, Public Staff witness Parcell, Commercial Group witnesses Chriss and Rosa, AGO witness Woolridge, CIGFUR III witness Phillips, Tech Customers witness Strunk, and CUCA witness O'Donnell. No rate of return on equity expert evidence was presented by any other party.

In addition to its evaluation of the expert evidence, the Commission must also make findings of fact regarding the impact of changing economic conditions on customers when determining the proper rate of return on equity for a public utility. Cooper I, 366 N.C. 484, 739 S.E.2d at 548. This was a factor newly announced by the Supreme Court in its Cooper I decision, and which was not previously required by the Commission, the Court of Appeals, or the Supreme Court as an element to be considered in connection with the Commission's determination of an appropriate rate of return on equity. The Commission's discussion of the evidence with respect to the findings required by Cooper I is set out in detail in this Order.

Cooper I was the result of the Supreme Court's reversal and remand of the Commission's approval of the agreement regarding the rate of return on equity in a stipulation between the Public Staff and DEC in DEC's 2011 Rate Case. The Commission has had occasion to apply both prongs of Cooper I in subsequent orders, specifically the following:

- Order Granting General Rate Increase in DEP's 2013 Rate Case, Docket No. E-2, Sub 1023 (May 30, 2013) (2013 DEP Rate Order), which was affirmed by the

Supreme Court in State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 444, 761 S.E.2d 640 (2014) (Cooper III);[9]

- Order on Remand resulting from the Supreme Court's Cooper I decision, in Docket No. E-7, Sub 989 (October 23, 2013) (DEC Remand Order), which was affirmed by the Supreme Court in State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 644, 766 S.E.2d 827 (2014) (Cooper IV);
- Order Granting General Rate Increase in DEC's 2013 Rate Case, Docket No. E-7, Sub 1026 (September 24, 2013) (2013 DEC Rate Order), which was affirmed by the Supreme Court in State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 741, 767 S.E.2d 305 (2015) (Cooper V);
- Order on Remand resulting from the Supreme Court's Cooper II decision, in Docket No. E-22, Sub 479 (July 23, 2015) (DNCP Remand Order), which was not appealed to the Supreme Court;
- Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions, in Docket No. E-22, Sub 532, dated December 22, 2016 (2016 DNCP Rate Order), which was not appealed to the Supreme Court; and
- Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, in Docket No. E-2, Sub 1142, dated February 23, 2018 (2018 DEP Rate Order).

In order to give full context to the Commission's decision herein and to elucidate its view of the requirements of the General Statutes as they relate to rate of return on equity, as interpreted by the Supreme Court in Cooper I, the Commission deems it important to provide in this Order an overview of the general principles governing this subject.

A. Governing Principles in Setting the Rate of Return on Equity

First, there are, as the Commission noted in the 2013 DEP Rate Order, constitutional constraints upon the Commission's rate of return on equity decisions established by the United States Supreme Court decisions in Bluefield Waterworks & Improvement Co., v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) (Bluefield), and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) (Hope):

> To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting an ROE, the Commission must still provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. State ex rel. Utils. Comm'n v. General Telephone Co. of the Southeast, 281 N.C.

[9] An intervening Cooper case, State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 430, 758 S.E.2d 635 (2014) (Cooper II), arose from the 2012 Rate Case by Dominion North Carolina Power (DNCP) and resulted in a remand to the Commission, inasmuch as the Commission's Order in that case predated Cooper I.

> 318, 370, 189 S.E.2d 705, 757 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return declared" in Bluefield and Hope. Id.

2013 DEP Rate Order, at 29.

Second, the rate of return on equity is, in fact, a cost. The return that equity investors require represents the cost to the utility of equity capital. In his dissenting opinion in Missouri ex rel. Southwestern Bell Tel. Co. v. Missouri Pub. Serv. Comm'n, 262 U.S. 276 (1923), Justice Brandeis remarked upon the lack of any functional distinction between the rate of return on equity (which he referred to as a "capital charge") and other items ordinarily viewed as business costs, including operating expenses, depreciation, and taxes:

> Each is a part of the current cost of supplying the service; and each should be met from current income. When the capital charges are for interest on the floating debt paid at the current rate, this is readily seen. But it is no less true of a legal obligation to pay interest on long-term bonds…and it is also true of the economic obligation to pay dividends on stock, preferred or common.

Id. at 306. (Brandeis, J. dissenting) (emphasis added). Similarly, the United States Supreme Court observed in Hope, "From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business…[which] include service on the debt and dividends on the stock." Hope, 320 U.S. at 591, 603.

Leading academic commentators also define rate of return on equity as the cost of equity capital. Professor Charles Phillips, for example, states that "the term 'cost of capital' may be defined as the annual percentage that a utility must receive to maintain its credit, to pay a return to the owners of the enterprise, and to ensure the attraction of capital in amounts adequate to meet future needs." Phillips, Charles F., Jr., The Regulation of Public Utilities (Public Utilities Reports, Inc. 1993), at 388. Professor Roger Morin approaches the matter from the economist's viewpoint:

> While utilities enjoy varying degrees of monopoly in the sale of public utility services, they must compete with everyone else in the free open market for the input factors of production, whether it be labor, materials, machines, or capital. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices which are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require, for example, the interest on capital debt, or the expected return on equity.

* * *

> [T]he cost of capital to the utility is synonymous with the investor's return, and the cost of capital is the earnings which must be generated by the investment of that capital in order to pay its price, that is, in order to meet the investor's required rate of return.

Morin, Roger A., Utilities' Cost of Capital (Public Utilities Reports, Inc. 1984), at 19-21 (emphasis added). Professor Morin adds: "The important point is that the prices of debt capital and equity capital are set by supply and demand, and both are influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities." Id. at 20 (emphasis added).

Changing economic circumstances as they impact DEC's customers may affect those customers' ability to afford rate increases. For this reason, customer impact weighs heavily in the overall rate setting process, including, as set out in detail elsewhere in this Order, the Commission's own decision of an appropriate authorized rate of return on equity. In addition, in the event of a settlement, customer impact no doubt influences the process by which the parties to a rate case decide to settle contested matters and the level of rates achieved by any such settlement.

However, a customer's ability to afford a rate increase has absolutely no impact upon the supply of or the demand for capital. The economic forces at work in the competitive capital market determine the cost of capital – and, therefore, the utility's required rate of return on equity. The cost of capital does not go down because some customers may find it more difficult to pay for an increase in electricity prices as a result of prevailing adverse economic conditions, any more than the cost of capital goes up because some customers may be prospering in better times.

Third, the Commission is and must always be mindful of the North Carolina Supreme Court's command that the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions. State ex rel. Utils. Comm'n v. Pub. Staff-N. Carolina Utils. Comm'n, 323 N.C. 481, 490, 374 S.E.2d 361, 370 (1988) (Public Staff). Further, and echoing the discussion above concerning the fact that rate of return on equity represents the cost of equity capital, the Commission must execute the Supreme Court's command "irrespective of economic conditions in which ratepayers find themselves." 2013 DEP Rate Order, at 37. The Commission noted in that Order:

> The Commission always places primary emphasis on consumers' ability to pay where economic conditions are difficult. By the same token, it places the same emphasis on consumers' ability to pay when economic conditions are favorable as when the unemployment rate is low. Always there are customers facing difficulty in paying utility bills. The Commission does not grant higher rates of return on equity when the general body of ratepayers is in a better position to pay than at other times, which would seem to be a logical but misguided corollary to the position the Attorney General advocates on this issue.

Id. Indeed, in Cooper I the Supreme Court emphasized "changing economic conditions" and their impact upon customers. Cooper I, 366 N.C. at 484, 739 S.E.2d at 548.

Fourth, while there is no specific and discrete numerical basis for quantifying the impact of economic conditions on customers, the impact on customers of changing economic conditions is embedded in the rate of return on equity expert witnesses' analyses. The Commission noted this in the 2013 DEP Rate Order: "This impact is essentially inherent in the ranges presented by the return on equity expert witnesses, whose testimony plainly recognized economic conditions – through the use of econometric models – as a factor to be considered in setting rates of return." 2013 DEP Rate Order, at 38.

Fifth, under long-standing decisions of the North Carolina Supreme Court, the Commission's subjective judgment is a necessary part of determining the authorized rate of return on equity. Public Staff, 323 NC 481, 490, 374 S.E.2d 361, 369. As the Commission also noted in the 2013 DEP Rate Order:

> Indeed, of all the components of a utility's cost of service that must be determined in the ratemaking process, the appropriate ROE [rate of return on equity] the one requiring the greatest degree of subjective judgment by the Commission. Setting an ROE [rate of return on equity] for regulatory purposes is not simply a mathematical exercise, despite the quantitative models used by the expert witnesses. As explained in one prominent treatise,
>
>> Throughout all of its decisions, the [United States] Supreme Court has formulated no specific rules for determining a fair rate of return, but it has enumerated a number of guidelines. The Court has made it clear that confiscation of property must be avoided, that no one rate can be considered fair at all times and that regulation does not guarantee a fair return. The Court also has consistently stated that a necessary prerequisite for profitable operations is efficient and economical management. Beyond this is a list of several factors the commissions are supposed to consider in making their decisions, but no weights have been assigned.
>>
>> The relevant economic criteria enunciated by the Court are three: financial integrity, capital attraction and comparable earnings. Stated another way, the rate of return allowed a public utility should be high enough: (1) to maintain the financial integrity of the enterprise, (2) to enable the utility to attract the new capital it needs to serve the public, and (3) to provide a return on common equity that is commensurate with returns on investments in other enterprises of corresponding risk. These three economic criteria are interrelated and have

> been used widely for many years by regulatory commissions throughout the country in determining the rate of return allowed public utilities.
>
> In reality, the concept of a fair rate of return represents a "zone of reasonableness." As explained by the Pennsylvania commission:
>
> > There is a range of reasonableness within which earnings may properly fluctuate and still be deemed just and reasonable and not excessive or extortionate. It is bounded at one level by investor interest against confiscation and the need for averting any threat to the security for the capital embarked upon the enterprise. At the other level it is bounded by consumer interest against excessive and unreasonable charges for service.
>
> As long as the allowed return falls within this zone, therefore, it is just and reasonable. . . . It is the task of the commissions to translate these generalizations into quantitative terms.

Charles F. Phillips, Jr., The Regulation of Public Utilities, 3d ed. 1993, pp. 382. (notes omitted).

2013 DEP Rate Order, pp. 35-36.

Thus, the Commission must exercise its subjective judgment so as to balance two competing rate of return on equity-related factors – the economic conditions facing the Company's customers and the Company's need to attract equity financing in order to continue providing safe and reliable service.

The Supreme Court in Cooper V affirmed the 2013 DEC Rate Order, in which this framework was fully articulated. But to the framework the Commission can add additional factors based upon the Supreme Court's decisions in Cooper III, Cooper IV, and Cooper V. Specifically, the Supreme Court held that nothing in Cooper I requires the Commission to "quantify" the influence of changing economic conditions upon customers (see, e.g., Cooper V, 367 N.C. at 745-46, 767 S.E.2d at 308; Cooper IV, 367 N.C. at 650, 766 S.E.2d at 829; Cooper III, 367 N.C. at 450, 761 S.E.2d at 644), and, indeed, the Supreme Court reiterated that setting the rate of return on equity is a function of the Commission's subjective judgment: "Given th[e] subjectivity ordinarily inherent in the determination of a proper rate of return on common equity, there are inevitably pertinent factors which are properly taken into account but which cannot be quantified with the kind of specificity here demanded by [the appellant]." Cooper III, 367 N.C. at 450, 761 S.E.2d at 644, quoting Public Staff, 323 N.C. at 498; 374 S.E.2d at 370.

Finally, the Supreme Court discussed with approval the Commission's reference to and reliance upon expert witness testimony that used econometric models that the Commission had noted "inherently" contained the effects of changing economic circumstances upon customers, and also discussed with approval the Commission's reference to and reliance upon expert witness testimony correlating the North Carolina economy with the national economy. See, e.g., Cooper V, 367 N.C. at 747, 767 S.E.2d at 308; Cooper III, 367 N.C. at 451, 761 S.E.2d at 644.

It is against this backdrop of overarching principles that the Commission turns to the evidence presented in this case.

B. Application of the Governing Principles to the Rate of Return Decision

1. Evidence from Expert Witnesses on Cost of Equity Capital

Company witness Hevert recommended in his direct testimony a rate of return on equity of 10.75%, which was slightly above the midpoint of his recommended range of 10.25% to 11.00%. Witness Hevert's direct testimony explained the importance of a utility being allowed to earn a rate of return on equity that is adequate to attract capital at reasonable terms, under varying market conditions, and that will enable the utility to provide safe, reliable electric service while maintaining its financial integrity. Witness Hevert explained that unlike the cost of debt, the cost of equity is not observable and must be estimated based on market data. Witness Hevert noted that since all financial models are subject to various assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return recommendations. Witness Hevert used the Constant Growth and Multi-Stage forms of the Discounted Cash Flow (DCF) model; the Capital Asset Pricing Model (CAPM); and the Bond Yield Risk Premium. He testified that his recommendation also takes into consideration factors such as DEC's generation portfolio and the risks associated with environmental regulations, flotation costs, and DEC's planned capital investment program. Witness Hevert also provided extensive testimony concerning the capital market environment and addressed the effect those market conditions have on the return investors require in order to commit their capital to equity securities. Witness Hevert also focused upon capital market conditions as they affect the Company's customers in North Carolina.

To calculate the dividend yield for the DCF, witness Hevert used the average daily closing prices for the 30-trading days, 90-trading days, and 180-trading days as of June 16, 2017. He then calculated the DCF results using each of the following growth terms:

- The Zack's consensus long-term earnings growth estimates;
- The First Call consensus long-term earnings growth estimates; and
- The Value Line earnings growth estimates.

Witness Hevert testified that for each proxy company he calculated the mean, mean high, and mean low results. For the mean result, he combined the average of the

EPS growth rate estimates reported by Value Line, Zacks, and First Call with the subject company's dividend yield for each proxy company and then calculated the average result for those estimates. His constant growth DCF results ranged from 7.91% to 9.83%.[10]

He testified with regard to his constant growth DCF that regardless of the method employed, an authorized rate of return on equity that is well below returns authorized for other utilities (1) runs counter to the Hope and Bluefield "comparable risk" standard, (2) would place DEC at a competitive disadvantage, and (3) makes it difficult for DEC to compete for capital at reasonable terms.

DEC witness Hevert testified that the Multi-Stage DCF model, which is an extension of the constant growth form, enables the analyst to specify growth rates over three distinct stages (i.e., time periods). As with the constant growth form of the DCF model, the Multi-Stage form defines the cost of equity as the discount rate that sets the current price equal to the discounted value of future cash flows. He testified in the first two stages, "cash flows" are defined as projected dividends. In the third stage, "cash flows" equal both dividends and the expected price at which the stock will be sold at the end of the period (i.e., the terminal price). He calculated the terminal price based on the Gordon model, which defines the price as the expected dividend divided by the difference between the cost of equity (i.e., the discount rate) and the long-term expected growth rate.

Witness Hevert testified that his Multi-Stage DCF long-term growth rate was 5.38% based on the real gross domestic product (GDP) growth rate of 3.22% from 1929 through 2016 and an inflation rate of 2.09%. He testified that the GDP growth rate is calculated as the compound growth rate in companies. Witness Hevert testified that his Multi-Stage DCF analysis produced a range of results from 8.70% to 9.31%. Using the proxy group price-to-earnings ratio to calculate a terminal valve, his Multi-Stage DCF produced a range of results from 9.52% to 11.05%.

Witness Hevert testified that for his CAPM analysis risk-free rate, he used the current 30-day average yield on 30-year Treasury bonds of 2.90% and the near-term projected 30-year Treasury yield of 3.40%. For the market risk premium, he calculated the market capitalization weighted average total return based on the constant growth DCF model for each of the Standard & Poor's (S&P) 500 companies using data from Bloomberg and Value Line. He then subtracted the current 30-year Treasury yield from that amount to arrive at the market DCF-derived forward looking market risk premium estimate. Witness Hevert used the beta coefficients reported by Bloomberg and Value Line. He testified that his CAPM analysis suggested a rate of return on equity range of 9.11% to 11.05%.

[10] Table 11 in the rebuttal testimony of witness Hevert contains updated analytical results for his DCF, CAPM, and Bond Yield Risk Premium analyses. However, in summarizing his rebuttal testimony, witness Hevert testified that "[n]one of their [opposing witnesses] arguments caused me to revise my conclusions or recommendations."

Witness Hevert testified that for his risk premium analysis, he estimated the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. He testified that the equity risk premium is typically estimated using a variety of approaches, some of which incorporate ex-ante, or forward-looking, estimates of the cost of equity, and others that consider historical, or ex-post, estimates. An alternative approach is to use actual authorized returns for electric utilities to estimate the equity risk premium.

Witness Hevert testified that he first defined the risk premium as the difference between the authorized rate of return on equity and the then-prevailing level of the long-term 30-year Treasury yield. He then gathered data for 1,517 electric utility rate proceedings between January 1980 and June 16, 2017. In addition to the authorized rate of return on equity, he also calculated the average period between the filing of the case and the date of the final order (the "lag period"). In order to reflect the prevailing level of interest rates during the pendency of the proceedings, he calculated the average 30-year Treasury yield over the average lag period of approximately 201 days. He testified that to analyze the relationship between interest rates and the equity risk premium, he used regression analyses. Witness Hevert testified that based upon the regression coefficients, the implied rate of return on equity in his risk premium analysis is between 9.97% and 10.33%.

Public Staff witness Parcell performed three rate of return on equity analyses using the constant growth DCF, the CAPM, and comparable earnings.

Witness Parcell considered five indicators of growth in his DCF analyses:

- Years 2012-2016 (five-year average) earnings retention, or fundamental growth (per Value Line);
- Five-year average of historic growth in EPS, dividends per share (DPS), and book value per share (BVPS) (per Value Line);
- Years 2017, 2018, and 2020-2022 projections of earnings retention growth (per Value Line);
- Years 2014-2016 to 2020-2022 projections of EPS, DPS, and BVPS (per Value Line); and
- Five-year projections of EPS growth (per First Call).

Witness Parcell testified that investors do not always use one single indicator of growth. His analysis using these five dividend growth indicators materially differed from DEC witness Hevert's sole use of analysts' predictions of EPS growth to determine DCF dividend growth.

Witness Parcell performed his DCF analysis on his proxy group of 11 companies, where using only the high mean growth rate the cost of capital was 8.2%, and the Hevert proxy group of 20 companies, where using only the highest mean growth rate the cost of capital was 9.2%. He recommended a DCF rate of return on equity of 8.7% for DEC as the mid-point of the two highest mean growth rates.

Witness Parcell testified that the constant growth DCF model currently produced cost of equity results that are lower than has been the case in recent years. This is, in part, a reflection of the decline in capital costs (e.g., in terms of interest rates). He believed that the constant growth DCF model remains relevant and informative. It was also his personal experience that of all available cost equity models, this model is used the most by cost of capital witnesses. Nevertheless, in order to be conservative, he focused only on the highest of the DCF results in making his recommendations.

Witness Parcell testified that he did not perform a multi-stage DCF, as he did not believe that the results of a properly-constructed multi-stage DCF would materially differ from the results of his constant-growth DCF.

Public Staff witness Parcell also performed a CAPM analysis, which describes the relationship between a security's investment risk and its market rate of return. For his risk-free rate, he used the three-month average yield for 20-year Treasury bonds. For the beta, which indicates the security's variability of return relative to the return variability of the overall capital market, he used the most recent Value Line beta for each company in his proxy group. He calculated the risk premium by comparing the annual returns on equity of the S&P 500 with the actual yields of the 20-year Treasury bonds, by comparing the total returns (i.e., dividends/interest plus gains/losses) for the S&P 500 group as well as long-term government bonds, using both the arithmetic and geometric means. These analyses revealed the average expected risk premium to be 5.8%. His CAPM results collectively indicated a rate of return on equity of 6.3% to 6.7% for the Parcell and Hevert proxy groups.

However, witness Parcell did not directly consider his CAPM results. He testified that he has conducted CAPM studies in his cost of equity analyses for many years. He stated that it is apparent that the CAPM results are currently significantly less than the DCF and comparable earnings results. According to his testimony, there are two reasons for the lower CAPM results. First, risk premiums are lower currently than was the case in prior years. This is the result of lower equity returns that have been experienced beginning with the Great Recession and continuing over the past several years. This is also reflective of a decline in investor expectations of equity returns and risk premiums. Second, the level of interest rates on Treasury bonds (i.e., the risk free rate) has been lower in recent years. This is partially the result of the actions of the Federal Reserve System to stimulate the economy. This also impacts investor expectation of returns in a negative fashion.

Witness Parcell testified that, initially, investors may have believed that the decline in Treasury yields was a temporary factor that would soon be replaced by a rise in interest rates. However, this has not been the case, as interest rates have remained low and have continued to decline for the past six-plus years. As a result, he believes that it cannot be maintained that low interest rates (and low CAPM results) are temporary and do not reflect investor expectations.

Consequently, the CAPM results should be considered as one factor in determining the cost of equity for DEC. Even though witness Parcell did not factor the CAPM results directly into his cost of equity recommendation, he believed these lower results are indicative of the recent and continuing decline in utility costs of capital, including the cost of equity.

Witness Parcell also performed a comparable earnings analysis. He testified that the cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk. He testified that the established legal standards are consistent with the opportunity cost principle. The two Supreme Court cases most frequently cited (Bluefield and Hope) hold that the return to the equity owners must be sufficient:

1. To maintain the credit of the enterprise and confidence in its financial integrity;
2. To permit the enterprise to attract required additional capital on reasonable terms; and
3. To provide the enterprise and its investors with an earnings opportunity commensurate with the returns available on investments in other enterprises having corresponding risks.

Witness Parcell further testified that the comparable earnings method normally examines the experienced and/or projected return on book common equity. The logic for examining returns on book equity follows from the use of original cost rate base regulation for public utilities, which uses a utility's book common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return, which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base rate of return methodology used to set utility rates. Witness Parcell applied the comparable earnings methodology by examining realized rates of return on equity for the Hevert and Parcell groups of proxy companies, as well as unregulated companies, and evaluated investor acceptance of these returns by reference to the resulting market-to-book ratios. Witness Parcell used the experienced rates of return on equity of the two proxy groups of utilities for the years 2002–2008 (the most recent business cycle) and 2009-2016 (the current business cycle), and projected return on equity for 2017, 2018, and 2020–2022 (the time periods estimated by Value Line). He testified that his results indicate that historic rates of return on equity of 9.7% to 11.0% have been adequate to produce market-to-book ratios of 145% to 159% for the groups of utilities. Furthermore, projected rates of return on equity for 2017, 2018, and 2020–2022 are within a range of 10.0% to 11.0% for the utility groups. These relate to market-to-book ratios of 178% or greater. He also noted that the rates of return on equity and market-to-book ratios of his proxy group, which all range over $20 billion in market value exceed those of witness Hevert's proxy group, which are not selected based upon size.

Witness Parcell also conducted a comparable earnings analysis examining the S&P's 500 Composite group. Over the same two business cycles, the group's average rates of return on equity ranged from 12.4% to 13.3%, with average market-to-books ranging between 233% and 275%. In order to apply the S&P 500 Composite rates of return on equity to the cost of equity for the proxy utilities, he compared the risk levels of the electric utilities and the competitive companies comparing the respective Value Line Safety Ranks, Value Line Betas, Value Line Financial Strengths, and S&P Stock Rankings, as shown on witness Parcell's direct testimony Exhibit DCP – 1, Schedule 12. Witness Parcell testified that based upon recent and prospective rates of return on equity and market-to-book analyses, his comparable earnings analysis indicates that the rate of return on equity for the proxy utilities is in the range of 9.0% to 10.0%.

Witness Parcell testified in support of the 9.9% rate of return on equity in the Stipulation. He explained that the Stipulation allows a 9.9% rate of return on equity and a capital structure of 52% equity and 48% long-term debt. Witness Parcell explained that the stipulated rate of return on equity is identical to the Commission's recent decisions in the 2016 DNCP Rate Order and the 2018 DEP Rate Order. The overall rate of return in the Stipulation is lower than the Company requested. Witness Parcell also explained that the 9.9% rate of return on equity falls within the range of his comparable earnings analysis.

Public Staff witness Parcell testified that in his experience, settlements are generally the result of good faith "give-and-take" and compromise-related negotiations among the parties of utility rate proceedings, involving the utility and other parties. He testified that it was also his understanding that settlements, as well as the individual components of the settlements, are often achieved by the respective parties' agreements to accept otherwise unacceptable individual aspects of individual issues in order to focus on other issues. He testified it was his understanding that the Stipulation is "global," except to the issues of Coal Ash (except for Coal Ash sales), Lee Nuclear return, nuclear decommissioning, updates, customer usage methodology, Federal income taxes, depreciation, Power Forward and the Grid Rider, and BFC.

Witness Parcell testified that it remains his position that should this be a fully litigated proceeding, he would continue to recommend a capital structure with 50% common equity and 50% long-term debt, a rate of return on equity of 9.10% (approximate mid-point of his range of 8.70% to 9.50%), and a cost of debt of 4.59%. However, given the benefits associated with entering into a settlement, it was his view that the cost of capital components of the Stipulation are a reasonable resolution to otherwise contentious issues.

Witness Parcell testified that each of the three cost of capital components - capital structure, rate of return on equity, and debt cost - can be considered as reasonable within the context of the Stipulation. He testified that DEC and the Public Staff, in their respective testimonies, proposed fundamentally different views on a number of issues, such as current market conditions and related current costs of common equity, as well as the appropriate capital structure. The Stipulation represents a compromise, or middle ground between their respective positions. He also testified that the cost of capital components of the Stipulation are reasonable within a broad negotiation and resolution of many of the issues in this proceeding.

With respect to the rate of return on equity component of the Stipulation, witness Parcell testified that DEC requested a rate of return on equity of 10.75%, which he noted in his direct testimony was well above industry norms in recent years. He recommended a 9.1% rate of return on equity (i.e., approximate mid-point of a rate of return on equity range of 8.70% to 9.50%, which was derived from his DCF model results of 8.7% and his comparable earnings results of 9.50%). Public Staff witness Parcell testified that while he continues to believe his specific 9.1% rate of return on equity recommendation is appropriate at this time, the upper end of his comparable earnings range of 9.0% to 10.0% contains the 9.9% Stipulation rate of return on equity level. He also stated that a 9.9% rate of return on equity is 0.80% above his 9.1% recommendation, and is 0.85% below DEC's 10.75% rate of return on equity request. As a result, the 9.9% rate of return on equity in the Stipulation is a "compromise" between DEC's and the Public Staff's respective proposals. The 9.9% rate of return on equity also reflects a reduction from the 10.2% authorized in DEC's last rate proceeding.

Witness Parcell testified that he had employed the comparable earnings method in virtually all of his cost of capital analyses going back to 1972. He testified that the comparable earnings analysis is based on the opportunity cost principle and is consistent with and derived from the Bluefield and Hope decisions of the U.S. Supreme Court, which are recognized as the primary standards for the establishment of a fair rate of return for a regulated public utility. The comparable earnings method is also consistent with the concept of rate base regulation for utilities, which employs the book value of both rate base and the capital financing rate base. He testified that his comparable earnings analyses consider the recent historic and prospective rates of return on equity for the groups of proxy utility companies utilized by himself and DEC witness Hevert. He testified that his conclusion of 9.0% to 10.0% reflects the actual rates of return on equity of the proxy companies, as well as the market-to-book ratios of these companies. Witness Parcell further testified that in the 2016 DNCP Rate Order, the Commission approved a settlement between DNCP and the Public Staff with a common equity ratio of 51.75% (versus the requested actual common equity ratio of 53.92%) and a rate of return on equity of 9.9% (versus the 10.5% requested), and in the 2018 DEP Rate Order, the Commission approved a common equity ratio of 52% versus the requested common equity ratio of 53%, and a rate of return on common equity of 9.9% versus the 10.75% DEP requested. The Commission approved the cost of capital components of both of those proposed settlements. Witness Parcell testified that the equity ratio and rate of return on equity in the Stipulation in the current DEC proceeding are consistent with those of the DNCP and DEP proceedings.

DEC witness Hevert also testified in support of the Stipulation on the agreed-upon rate of return on equity, capital structure, and overall rate of return contained in the Stipulation. He testified that although the stipulated rate of return on equity is below the lower bound of his recommended range of 10.25%, he recognized that the Stipulation represents negotiations among DEC and the Public Staff regarding otherwise contested issues. He testified that the Company has determined that the terms of the Stipulation, in particular the stipulated rate of return on equity and equity ratio, would be viewed by the rating agencies as constructive and equitable, and that he understands and respects that determination.

Witness Hevert testified that although the stipulated rate of return on equity falls below his recommended range, the low end of which is 10.25%, it is within the range of the analytical results presented in his direct and rebuttal testimonies. He testified that capital market conditions continue to evolve and as a consequence, the models used to estimate the cost of equity produce a wide range of estimates. Witness Hevert testified that he recognizes the benefits associated with DEC's decision to enter into the Stipulation and as such, it is his view that the 9.90% stipulated rate of return on equity is a reasonable resolution of an otherwise contentious issue.

Witness Hevert testified that he considered the stipulated rate of return on equity in the context of authorized returns for other vertically-integrated electric utilities. He testified that from January 2014 through February 2018, the average authorized rate of return on equity for vertically-integrated electric utilities was 9.81%, only nine basis points from the stipulated rate of return on equity. Of the 88 cases decided during that period, 33 included authorized returns of 9.90% or higher.

Witness Hevert testified that given DEC's need to access external capital and the weight rating agencies place on the nature of the regulatory environment, he believes it is important to consider the extent to which the jurisdictions that recently have authorized rates of return on equity for electric utilities are viewed as having constructive regulatory environments. Witness Hevert testified that North Carolina generally is considered to have a constructive regulatory environment. He testified that Regulatory Research Associates (RRA), which is a widely referenced source of rate case data, provides an assessment of the extent to which regulatory jurisdictions are constructive from investors' perspectives, or not. As RRA explains, less constructive environments are associated with higher levels of risk:

> RRA maintains three principal rating categories, Above Average, Average, and Below Average, with Above Average indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint, and Below Average indicating a less constructive, higher-risk regulatory climate from an investor viewpoint, Within the three principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a strong (more constructive) rating; 2, a mid-range rating; and 3, a weaker (less constructive) rating. We endeavor to maintain an approximate equal number of ratings above the average and below the average.[11]

[11] Source: RRA, accessed November 20, 2017.

Within RRA's ranking system, North Carolina is rated "Average/1," which witness Hevert testified falls in the top one-third of the 53 regulatory commissions ranked by RRA. Witness Hevert testified that the stipulated rate of return on equity falls ten to 12 basis points below the mean and median authorized rate of return on equity, respectively, for jurisdictions that are comparable to North Carolina's constructive regulatory environment, and 40 basis points above the median return authorized in less supportive jurisdictions. Taken from that perspective, the stipulated rate of return on equity is a reasonable, if not somewhat conservative, measure of DEC's cost of equity.

AGO witness Woolridge performed a DCF and CAPM for both his and witness Hervert's proxy groups of electric utilities. Witness Woolridge developed his DCF growth rate after reviewing 13 growth rate measures including historic and projected growth rate measures and evaluating growth in dividends, book value, EPS, and growth rate forecasts from Yahoo, Reuters, and Zack's. AGO witness Woolridge testified that it is well known that long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. AGO witness Woolridge in his supplemental testimony revised his DCF equity cost rate to 8.80% for his proxy group, and 8.80% for the Hevert proxy group.

In witness Woolridge's CAPM, he used for the risk free interest rate the yield on 30-year U.S. Treasury bonds. He used the Value Line Investment Survey betas of 0.70 for his proxy group and 0.70 for witness Hevert's proxy group. Witness Woolridge's market risk premium was 5.5% based in part upon the September 2017 CFO survey conducted by CFO Magazine and Duke University, which included approximately 300 responses, in which the expected market risk premium was 4.32%. He testified thus, that his 5.5% value is a conservatively high estimate of the market risk premium. Witness Woolridge also testified that Duff & Phelps, a well-known valuation and corporate finance advisor that publishes extensively on cost of capital, recommended in 2017 using a 5.5% market risk premium, for the U.S. Witness Woolridge's CAPM equity cost rate was 7.9% for both his and witness Hevert's proxy groups. Witness Woolridge gave primary weight to his DCF results in both his direct and supplemental testimony.

CUCA witness O'Donnell testified that the most useful methodology to produce realistic rate of return on equity results relative to prevailing capital markets, when applied appropriately, is the DCF. To check the reasonableness of his DCF analysis and to gauge the proper rate of return on equity to recommend within the DCF range, he also performed a comparable earnings analysis and CAPM. Witness O'Donnell utilized a proxy group similar to DEC witness Hevert's, except witness O'Donnell eliminated SCANA and Dominion, as these companies are involved in ongoing merger discussions.

Witness O'Donnell calculated his DCF dividend growth rate using the historical retention of earnings, the historical ten-year and five-year compound annual EPS, DPS, and BVPS as reported by Value Line, the Value Line forecasted compound annual rate of change for EPS, DPS, and BVPS, and the forecasted rate of change for EPS that industry analysts supplied to Charles Schwab and Company. Witness O'Donnell's DCF growth rate range was 4.75% to 5.75%, and his calculated DCF range was 8.0% to 9.0%.

In his comparable earning analysis, CUCA witness O'Donnell examined the earned returns on equity for his proxy group and Duke Energy Corporation over the period 2015 through 2022, balancing historical and forecasted returns. The past and forecasted earned returns for the proxy group were 9.25% to 10.25%, and the past and forecasted earned returns for Duke Energy Corporation were 7.5% to 8.5%. His recommended rate of return on equity based upon his comparable earnings analysis ranged from 8.75% to 9.75%.

Witness O'Donnell testified that for his CAPM, he used for the risk-free rate and the current 30-year Treasury bond yields of 2.9%. He expected the current interest rate environment to remain relatively stable for many years to come, citing statements by Federal Reserve Chairperson Janice Yellen. "Yellen Says Forces Holding Down Rates May Be Long Lasting," Barrons, June 16, 2016. The beta used for his proxy group was 0.72 and the beta for Duke Energy Corporation was 0.60. To determine the risk premium in his CAPM, witness O'Donnell used the long-term geometric and arithmetic returns for both large company equities and fixed income Long-Term Government Bonds with the resulting risk premium ranging from 4.60% to 6.20%. He also evaluated the predicted total market returns by a group of market experts, which ranged from 4.5% to 8%. He concluded that his equity risk premium was in the range of 4% to 6% and his CAPM resulted in a return on equity range of 5.06% to 7.52%.

Commercial Group witnesses Chriss and Rosa testified that the average of 97 reported electric utility rate case rates of return on equity authorized by commissions to investor-owned utilities in 2015, 2016 and 2017 was 9.63%. Witnesses Chriss and Rosa further testified that for the group reported by SNL Financial in Commercial Group Exhibit CR-3, the average rate of return on equity for vertically integrated utilities authorized from 2015 through 2017 is 9.78%, which includes the significant outlier 11.95% approved for Alaska Electric Light Power in Docket No. U-16-086, Order dated November 15, 2017. Witnesses Chriss and Rosa testified the average rate of return on equity authorized for vertically integrated utilities was in 2015, 9.75%; in 2016, 9.77%; and in 2017, 9.78%.

Witnesses Chriss and Rosa testified that they know the rate of return on equity decisions of other state regulatory commissions are not binding on the Commission. They testified that each commission considers the specific circumstances in each case in its determination of the proper rate of return on equity. They provided information in their testimony to illustrate a national customer perspective on industry trends in authorized rates of return on equity. These witnesses testified that in addition to using recent authorized rates of return on equity as a general gauge of reasonableness for the various cost-of-equity analyses presented in this case, the Commission should consider how its authorized rate of return on equity impacts North Carolina customers relative to other jurisdictions.

CIGFUR III witness Phillips did not perform cost of capital analyses. He testified that DEC's requested rate of return on equity of 10.75% is excessive and should be rejected. He stated that DEC's current authorized rate of return on equity is 10.2%, which was authorized in the Commission's 2013 DEC Rate Order issued on September 24,

2013. Witness Phillips testified that costs of capital have declined since DEC's last rate case. Every quarter, RRA, an affiliate of SNL Financial, updates its Major Rate Case Decisions report that covers electric and natural gas utility rate case outcomes. Specifically, this report tracks the authorized rates of return on equity resulting from utility rate cases. The most recent report, updated through September 30, 2017, shows that the national average authorized rate of return on equity for electric utilities in the first nine months of this year is 9.63%, nearly 60 basis points below DEC's currently authorized rate of return on equity. Witness Phillips concluded that DEC's current approved rate of return on equity, and definitely DEC's requested rate of return on equity, are significantly above the current market cost of equity. Witness Phillips recommended that the Commission authorize a rate of return on equity that does not exceed the national average of 9.63%.

Tech Customers witness Strunk did not perform rate of return on equity analyses. Instead, his cost of capital testimony focused on criticism of DEC witness Hevert assigning a higher risk factor to DEC than the electric utilities in witness Hevert's proxy group.

Witness Strunk testified that witness Hevert has not done any quantitative analysis to support his testimony that DEC has a comparatively high level of capital expenditures, nor has DEC's witness Hevert done any comparative analysis to support his contention that DEC faces higher risks of environmental regulation than witness Hevert's proxy group. Witness Strunk also testified that DEC witness Hevert's upward risk adjustment for the regulatory environment in which DEC operates is not justified, as North Carolina's regulatory climate is favorable relative to other states.

2. Discussion of Rate of Return Evidence and Conclusions

In a fully contested rate case such as, for example, the 2012 DNCP rate case, there will almost inevitably be conflicting rate of return on equity expert testimony. Even in a partially settled case, the Commission may be faced with conflicting rate of return on equity expert witnesses whose testimony, in accordance with CUCA I and Cooper I, requires detailed consideration and, as necessary, evaluation by the Commission of competing methodologies, opinions, and recommendations. These were the circumstances in DEC's 2011 rate case, Docket No. E-7, Sub 989, which resulted in the Cooper I decision, as well as the 2013 DEP Rate Case. In both of those cases, rate of return on equity expert testimony from CUCA witness O'Donnell provided an alternate rate of return on equity analysis that pegged the utility's cost of capital at an amount lower than the settled rate of return on equity. The Supreme Court in Cooper I faulted the Commission for not making explicit its evaluation of this testimony, and, thus, the Commission in the 2013 DEP Rate Order made an express evaluation of witness O'Donnell's testimony in accordance with the Cooper I decision.

The Commission determines the appropriate rate of return on equity based upon the evidence and particular circumstances of each case. However, the Commission believes that the rate of return on equity trends and decisions by other regulatory authorities deserve some weight, as (1) they provide a check or additional perspective on the case-specific circumstances, and (2) the Company must compete with other regulated utilities in the capital markets, meaning that a rate of return on equity significantly lower than that approved for other utilities of comparable risk would undermine the Company's ability to raise necessary capital, while a rate of return on equity significantly higher than other utilities of comparable risk would result in customers paying more than necessary. In this connection, the analysis performed by Commercial Group witnesses Chriss and Rosa, as modified by witness Hevert, is instructive. Witnesses Chriss and Rosa noted that according to data from SNL Financial for 2015 through 2017, authorized rates of return on equity across the country for vertically-integrated electric utilities have been in the range of 9.10% to 10.55%, excluding the Alaska Electric Light and Power significant outlier at 11.95%. Witnesses Chriss and Rosa calculated the mean authorized rate of return on equity for vertically-integrated utilities like DEC to be 9.78%. Witness Hevert, in commenting upon and evaluating their testimony in his Rebuttal Testimony, refined their analysis and presented his findings in Exhibit RBH-R28 to add in jurisdictional rankings. Doing so results in a rate of return on equity range from 9.80% to 10.55%, with a median of 10.0%. Tr. Vol. 4, p. 393. The Stipulation rate of return on equity is, of course, within that range, and actually below the median of that range. As witness Hevert's settlement testimony notes, "since 2014, the average authorized Return on Equity for vertically integrated electric utilities has been 9.81%, only nine basis points from the Stipulation rate of return on equity. Among jurisdictions that, like North Carolina, are seen as having constructive regulatory environments, the average authorized ROE [rate of return on equity] was 10.02%, 12 basis points above the 9.90% Stipulation ROE [rate of return on equity]." Id. at 418. Accordingly, the evidence presented concerning other authorized rates of return on equity, when put into proper context, lends substantial support to the stipulated 9.9% rate of return on equity level.

Finally, as the Supreme Court made clear in CUCA I and CUCA II, the Commission should give consideration to the non-unanimous Stipulation as relevant evidence, along with all evidence presented by other parties, in determining whether the Stipulation's provisions should be accepted. In this case, insofar as expert rate of return on equity testimony is concerned, no expert witness presented credible or substantial evidence that the stipulated 9.9% rate of return on equity is not just or reasonable to all parties. Both witnesses Hevert and Parcell supported DEC's required rate of return on equity at that level, in the context of the Stipulation as a whole, and witness Hevert was subjected to extensive cross-examination. Thus, the Commission finds and concludes that the Stipulation, along with the expert testimony of witnesses Hevert (risk premium analysis), O'Donnell (comparable earnings), and Parcell (comparable earnings), are credible and substantial evidence of the appropriate rate of return on equity and are entitled to substantial weight in the Commission's determination of this issue.

3. Evidence of Impact of Changing Economic Conditions on Customers

As noted above, utility rates must be set within the constitutional constraints made clear by the United States Supreme Court in Bluefield and Hope. To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting a return on equity, the Commission must nonetheless provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. State ex rel. Utils. Comm'n v. General Telephone Co. of the Southeast, 281 N.C. 318, 370, 189 S.E.2d 705 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return declared" in Bluefield and Hope. Id.

a. Discussion and Conclusions Regarding Evidence Introduced During the Expert Witness Hearing

In this case, all parties had the opportunity to present the Commission with evidence concerning changing economic conditions as they affect customers. The testimony of witnesses Hevert and Parcell, which the Commission finds entitled to substantial weight, addresses changing economic conditions at some length. Witness Hevert provided detailed data concerning changing economic conditions in North Carolina as well as nationally, and concluded that the North Carolina-specific conditions are "highly correlated" with conditions in the broader nationwide economy. As such, witness Hevert testified that changing economic conditions, both nationally and specific to North Carolina, are reflected in his rate of return on equity estimates.

DEC witness Hevert testified extensively on economic conditions in North Carolina. He testified that unemployment has fallen substantially in North Carolina and the U.S. since late 2009 and early 2010, when the rates peaked at 10.00% and 11.30%, respectively. By May 2017, the unemployment rate had fallen to one-half of those peak levels: 4.30% nationally, and 4.50% in North Carolina. Since DEC's last rate filing in 2013, the unemployment rate in North Carolina has fallen from 8.70% to 4.50%.

Witness Hevert testified that with respect to GDP, there also has been a relatively strong correlation between North Carolina and the national economy (approximately 69.00%). Since the financial crisis, the national rate of growth at times (during portions of 2010 and 2012) outpaced North Carolina. Since the third quarter of 2015, however, North Carolina has consistently exceeded the national growth rate. He testified that as to median household income, the correlation between North Carolina and the U.S. is relatively strong (nearly 86.18% from 2005 through 2015). Since 2009 (that is, the years subsequent to the financial crisis), median household income in North Carolina has grown at a faster annual rate than the national median income.

Witness Hevert testified as to the seasonally unadjusted unemployment rates in the counties served by DEC. At the unemployment peak, which occurred in late 2009 into early 2010, the unemployment rate in those counties reached 13.80% (1.80 percentage points higher than the State-wide average); by April 2017 it had fallen to approximately 4.15% (0.15 percentage points lower than the State-wide average). Since DEC's last rate filing in 2013, these counties' unemployment rates have fallen by over 5.70 percentage points.

Witness Hevert testified that it is his opinion that, based on the indicators discussed above, North Carolina and the counties contained within DEC's service area continue to steadily emerge from the economic downturn that prevailed during DEC's previous rate case, and that they have experienced significant economic improvement during the last several years. He testified that this improvement is projected to continue.

Public Staff witness Parcell testified that he is aware of no clear numerical basis for quantifying the impact of changing economic conditions on customers in determining an appropriate rate of return on equity in setting rates for a public utility. He testified that the impact of changing economic conditions nationwide is inherent in the methods and data used in his study to determine the cost of equity for utilities that are comparable in risk to DEC.

Witness Parcell testified that DEC provides service in 44 counties, and that the 11 counties North Carolina Department of Commerce classified as Tier 1 counties had an August 2017 not-seasonally-adjusted combined unemployment rate of 4.5%, with a combined total of 6,177 persons unemployed, and a combined total labor force of 136,989 persons. The 21 Tier 2 counties had an August 2017 not-seasonally-adjusted combined unemployment rate of 4.6%, with a combined total of 54,552 persons unemployed and a combined total labor force of 1.193 million persons. The 12 Tier 3 counties had an August 2017 not-seasonally-adjusted combined unemployment rate of 4.0%, with a combined total of 80,066 persons unemployed, with a combined total labor force of 2.009 million persons. The August 2017 not-seasonally-adjusted North Carolina unemployment rate was 4.5%. He testified that all 44 counties experienced a drop in their not-seasonally-adjusted unemployment rates between August 2016 and August 2017, averaging a 0.8% decrease compared to the statewide decrease of 0.8%. Witness Parcell further testified that the North Carolina Department of Commerce in its December 2017 NC Today stated that North Carolina industry employment had an increase of 71,500 over the year, an increase in real taxable retail sales of $401.0 million over the year, an increase in residential building permits of 16.9% over the year, and an increase in job postings of 12.2% over the year. Witness Parcell testified that there are reasons to believe that the economic conditions in the nation and in North Carolina will continue to improve, which should provide a benefit for many DEC customers. He concluded by stating that the Commission's duty to set rates as low as reasonably possible consistent with constitutional requirements without jeopardizing adequate and reliable service is the same regardless of the customer's ability to pay.

b. Evidence Introduced During Public Witness Hearings and Further Conclusions

The Commission's review also includes consideration of the evidence presented, primarily by way of non-expert witness testimony, at three evening hearings held throughout DEC's North Carolina service territory to receive public witness testimony. The public witness hearings held in this proceeding afforded 75 public witnesses, most of whom are customers of DEC, the opportunity to be heard regarding their respective positions on DEC's application for a general rate increase. The testimony presented at the non-expert witness hearings illustrates in detail the difficult economic conditions facing many DEC customers, and the witnesses' general objection to DEC recovering costs related to coal ash cleanup. More than 20 witnesses testified that the rate increase was not affordable for many customers, including those on fixed incomes, the elderly, persons with disabilities, the under- and unemployed, and the poor. Notably, a number of customers also expressed the view that the Company should be required to revise its current grid modernization plans in favor of increased energy efficiency and renewable energy resources initiatives. A representative sample of the public witness testimony received is summarized below.

Summary of Testimony Received in Franklin

At the hearing in Franklin, witnesses Watters, Bugash, Friedman, and Corbin acknowledged that DEC provides reliable electric service, and is responsive when power outages occur, particularly those that are weather-related or caused by natural disasters. Notwithstanding their general satisfaction with electric service reliability, neither witness Watters nor witness Bugash supports DEC's requested rate increase. Witness Lawley, on the other hand, testified that DEC does not provide adequate or reliable electric service, particularly to those customers who live in the mountains, and that minor inclement weather can result in power outages that take DEC days or weeks to resolve. Witness Lawley testified that the power has gone out at her residence nearly 100 times during a two-year period. Witness Lawley testified that DEC claimed that the outages were caused by squirrels, but she opined that the outages actually were the result of a defective piece of equipment that DEC failed to timely fix. Witness Boyd testified that he also does not receive reliable electric service from DEC and opined that this is in part due to DEC's failure to adequately manage vegetation in the area. Witness Crownover testified that she was overcharged by DEC for many years due to having been listed incorrectly by DEC as a recipient of natural gas utility service. Chairman Finley directed DEC to investigate the service and billing complaints of these witnesses, and to report to the Commission the results thereof.

Witness Watters testified that it is unfair that the lowest energy users are charged a higher variable rate for energy than those customers who consume larger amounts of energy. Witnesses Watters, Friedman, and Smith testified that DEC should be doing more to transition from coal and natural gas to renewable energy, including solar and wind power.

Witnesses Sparks, Erickson, Horton, Crawford, Boyd, and Smith oppose a rate increase because, in their opinion, DEC's financial position is healthy enough such that a rate increase is unnecessary. Witnesses Sparks, Horton, Lawley, Zwinak, Wilde, Smith, and Corbin testified that customers living on a fixed or low income, including senior citizens and those living with disabilities, cannot afford a rate increase. Witness Wilde testified that "even [] a one cent increase in electric" costs would break the already stretched fixed-incomes of the elderly. Tr. Vol. 1, p. 64. After explaining that a number of counties across North Carolina face significant economic distress, witness Smith, a former Board Chair of the Jackson-Macon Conservation Alliance, expressed concern that the suggested rate hike would be "shared equally among all counties, despite enormous economic disparities." Id. at 66. Any rate increase, Mr. Smith concluded, would "translate to real sacrifices for working families" in those counties. Id. at 68. Witness Smith further testified that a rate increase would discourage energy efficiency and conservation measures.

Witnesses Sparks, Erickson, Crawford, Bugash, Friedman, Lawley, Zwinak, Crownover, Wilde, and Smith testified that DEC's shareholders, and not its ratepayers, should be required to bear the costs of DEC's mismanagement in failing to properly handle and dispose of coal ash. Witnesses Lawley and Smith testified that those customers directly affected by DEC's coal ash mismanagement have been drinking bottled water for a long time and have not received any reimbursement for their losses, but still would be subject to paying for a rate increase to remedy DEC's environmental non-compliance. Witnesses Friedman and Lawley also oppose the cost recovery for the canceled Lee nuclear plant.

Witness Lawley testified that, in his opinion, the infrastructure of DEC's electric grid is inadequate, and that DEC is not doing enough to improve redundancy. Witness Lawley also, however, opposes DEC's proposed grid modernization initiative because of its vagueness and cost.

In its March 29, 2018 Customer Inquiry Follow-up Report, DEC stated that it investigated and resolved the service complaints of witnesses Lawley and Crownover. DEC's March 29, 2018 Customer Inquiry Follow-up Report did not address the complaint of witness Boyd, however.

Summary of Testimony Received in Greensboro

Witness Goodson, the Executive Director for the North Carolina Community Action Association, thanked DEC for its current programs designed to aid low-income individuals and requested that the Company increase its spending on such programs, including its energy efficiency weatherization program.

Witnesses Goodson, Wright, Bass, Merrell, Concepcion, Preschle, Phillips, Stevenson, Diaz-Reyes, Smith, Ruder, Ellison, Kriegsman, Freeman, Hutchby, and Longstreet testified that many ratepayers cannot afford a rate increase, particularly the under- and unemployed and those living on low or fixed incomes, including students, persons with disabilities, the elderly, and the poor. Witnesses Wright and Diaz-Reyes also testified that those who would have a difficult time paying for a rate increase also are the customers likely to use more energy due to living in older, more poorly insulated homes. Witness Sevier, a member of AARP, testified that homeless students, in addition to Social Security recipients, would not be able to pay for a rate increase. Witness Petty testified that the rate increase would disproportionately affect the budgets of low income individuals more so than those with disposable income. Witness Concepcion complained that her electric bill was unreasonably high for January 2018.

Witnesses Carter, Wright, Phillips, Stevenson, and Hutchby testified that, in their opinion, DEC's financial position is healthy enough such that a rate increase is unnecessary. Witness Stevenson testified that the recent federal tax cut should obviate the need for some or all of DEC's requested rate increase.

Witnesses A. Martin, R. Martin, Graham, Bass, Merrell, Concepcion, Tuch, Preschle, Lange, Phillips, Bishop, Diaz-Reyes, Smith, Robins, Fansler, Kriegsman, Motsinger, and Hutchby testified that DEC's shareholders, and not its ratepayers, should be required to bear the costs of DEC's mismanagement in failing to properly handle and dispose of coal ash. Witness Graham testified that she lives near a DEC coal ash pit and, as a result, has had to live on bottled water for over 1,000 days. Witnesses Graham, Fansler, and Hutchby testified that it is wrong to ask those who have been directly harmed by DEC's coal ash management practices to also pay more for their electric service.

Witnesses A. Martin and Tuch testified in support of DEC's efforts toward increasing renewable energy and contend they would be willing to pay a premium for their electric service to support those endeavors. Witness Tuch, the Chair of the North Carolina Climate Solutions Coalition, testified that Duke should be planning to transition to 100 percent cleaner, renewable energy by 2050. Witnesses Preschle and Diaz-Reyes testified that DEC should be more focused on cost-effective clean energy and sustainability practices, including offshore wind energy. Witness Freeman testified that the proposed increase to the basic customer charge is unfair to low-income customers and those who use the least amount of energy, including those customers who employ energy efficiency or have invested in renewable energy measures.

Witnesses Bishop and Fansler oppose the cost recovery for the canceled Lee nuclear plant. Witnesses Stevenson and Kriegsman testified in opposition to DEC's proposed grid modernization initiative, stating that the program lacks transparency and "detailed insight, given the recent failed nuclear ventures, also because the grid mods are future investment and the other issues are past failures." Tr. Vol. 2, p. 64. Witness Ruder opposes cost recovery for AMI smart meters and opines that they were "a very bad investment," about which customers have had a number of complaints. Id. at 71.

In its March 29, 2018 Customer Inquiry Follow-up Report, DEC stated that it investigated and resolved the billing complaint of witness Concepcion. DEC's March 29, 2018 Customer Inquiry Follow-up Report did not address the complaint of witness Graham.

Summary of Testimony Received in Charlotte

Witnesses Kasher, Taylor, English, Nicholson, Satterfield, Brown, Hollis, McLaney, Moore, Henry, Sprouse, Blotnick, Copulsky, Jones, Segal, Lauer, Eddleman, and Mitchell testified that DEC's shareholders, and not its ratepayers, should be required to bear the costs of DEC's mismanagement in failing to properly handle and dispose of coal ash. Witnesses English, Nicholson, and Satterfield testified that allowing DEC to charge its ratepayers for coal ash cleanup would set problematic precedent in the event of future environmental issues. Witnesses Brown and Lauer testified to the direct impacts that DEC's coal ash mismanagements have had on their lives, including their water supply, and opined that it is wrong to ask those who have been directly harmed by DEC's coal ash management practices to pay more for their electric service. Witness Eddleman testified that DEC has "always refused to line their coal ash pits." Tr. Vol. 3, p. 115.

Witnesses Nicholson, Dawson, Segal, and Eddleman testified that DEC's financial position is healthy enough such that a rate increase is unnecessary. Witnesses Kasher and Sparrow testified that the recent federal tax cut should obviate the need for some or all of DEC's requested rate increase.

Witnesses Kasher, English, Kneidel, Crawford, Blotnick, King, Houlihan, Jones, Eddleman, and Adams testified that DEC should be more focused on cleaner, cheaper renewable energy, including wind and solar. Witnesses Kneidel, Moore, Henry, King, Houlihan, Copulsky, Rose, and Adams testified that DEC's proposed grid modernization initiative is vague and will not do enough to connect more, clean, renewable energy to the grid. Witnesses Moore, Henry, Blotnick, King, and Houlihan testified that DEC has not justified its planned grid modernization spending, particularly since it will not help to lower bills or conserve electricity and does not involve actual modernization of the grid. Witness Henry also testified in opposition to DEC's proposed cost allocation for its grid modernization spending.

Witnesses Baker, Williams, Taylor, Nicholson, Hollis, Johnson, Dawson, Jones, Cano, Segal, and Mitchell testified that many ratepayers cannot afford a rate increase, particularly the under- and unemployed and those on low or fixed incomes, including the elderly, persons with disabilities, and the poor. Witnesses Satterfield, Hollis, Blotnick, and Eddleman oppose DEC's proposed basic customer charge increase because it disproportionately affects low-income individuals and those that use the least amount of energy or practice energy conservation measures.

Witnesses English, Nicholson, Satterfield, Henry, Sprouse, Copulsky, Eddleman, and Adams testified in opposition to cost recovery for the canceled Lee nuclear plant.

In its March 29, 2018 Customer Inquiry Follow-up Report, DEC stated that it investigated the complaint of witness Lauer and determined that the location at issue is served by Rutherford Electric Membership Corporation, not DEC. DEC's March 29, 2018 Customer Inquiry Follow-up Report did not address the complaint of witness Brown.

The Commission accepts as credible and probative the testimony of public witnesses, illustrating the economic strain felt by many North Carolina citizens, while also reflecting their interests in energy efficiency and renewable energy. The Commission also accepts as credible and probative the testimony of witness Hevert indicating that economic conditions in North Carolina are highly correlated with national conditions, and that such conditions are reflected in his econometric analyses and resulting rate of return on equity recommendations.

c. Commission's Decision Setting Rate of Return and Approving Rate Adjustment Takes Into Account and Ameliorates the Impact of Current Economic Conditions on Customers

As noted above, the Commission's duty under N.C. Gen. Stat. § 62-133 is to set rates as low as reasonably possible without impairing the Company's ability to raise the capital needed to provide reliable electric service and recover its cost of providing service. The Commission is especially mindful of this duty in light of the evidence in this case concerning the impact of current economic conditions on customers.

Chapter 62 in general, and N.C. Gen. Stat. § 62-133 in particular, set forth an elaborate formula the Commission must employ in establishing rates. The rate of return on cost of property element of the formula in N.C. Gen. Stat. § 62-133(b)(4) is a significant, but not independent one. Each element of the formula must be analyzed to determine the utility's cost of service and revenue requirement. The Commission must make many subjective decisions with respect to each element in the formula in establishing the rates it approves in a general rate case. The Commission must approve accounting and pro forma adjustments to comply with N.C. Gen. Stat. § 62-133(b)(3). The Commission must approve depreciation rates pursuant to N.C. Gen. Stat. § 62-133(b)(1). The decisions the Commission makes in each of these subjective areas have multiple and varied impacts on the decisions it makes elsewhere in establishing rates, such as its decision on rate of return on equity.

Economic conditions existing during the test year, at the time of the public hearings, and at the date of this Order affect not only the ability of DEC's customers to pay electric rates, but also the ability of DEC to earn the authorized rate of return during the period rates will be in effect. Pursuant to N.C. Gen. Stat. § 62-133, rates in North Carolina are set based on a modified historic test period.[12] A component of cost of service as important as return on investment is test year revenues.[13] The higher the level of test year revenues the lower the need for a rate increase, all else remaining equal. Historically, and in this case, test year revenues are established through resort to regression analysis, using historic rates of revenue growth or decline to determine end of test year revenues.

DEC is in a significant construction mode – adding new gas-fired plants, retrofitting nuclear units, and investing in transmission and distribution facilities. Much of this investment is responsive to environmental regulatory requirements. New gas units will replace older, less efficient, higher polluting coal units. These units do little to meet new growth.

When costs and expenses grow at a faster pace than revenues during the period when rates will be in effect, the utility will experience a decline in its realized rate of return on investment to a level below its authorized rate of return. Differences exist between the authorized return and the earned, or realized, return. Components of the cost of service

[12] N.C. Gen. Stat. § 62-133(c)

[13] N.C. Gen. Stat. § 62-133(b)(3).

must be paid from the rates the utility charges before the equity investors are paid their return on equity. Operating and administrative expenses must be paid, depreciation must be funded, taxes must be paid, and the utility must pay interest on the debt it incurs. To the extent revenues are insufficient to cover the entire cost of service, the shortfall reduces the return to the equity investor, last in line to be paid. When this occurs, the utility's realized, or earned, return is less than the authorized return.

This phenomenon, caused by incurrence of higher costs prior to the implementation of new rates to recover those higher costs, is commonly referred to as regulatory lag. Just as the Commission confronts constitutional and statutory restrictions in making discrete decrements to rate of return on equity to mitigate the impact of rates on consumers, it also confronts statutory constraints on its ability to adjust test year revenues to mitigate for regulatory lag. The Commission, in its expert experience and judgment and based on evidence in the record, is aware of the effects of regulatory lag in the existing economic environment. However, just as the Commission is constrained to address difficult economic times on customers' ability to pay for service by establishing a lower rate of return on equity in isolation from the many subjective determinations that must be made in a general rate case, it likewise does not address the effect of regulatory lag on the Company by establishing a higher rate of return on equity. Instead, in setting the rate of return, the Commission considers both of these negative impacts in its ultimate decision fixing DEC's rates. The Commission keeps all factors affected by current economic conditions in mind in the many subjective decisions it makes in establishing rates. In doing so in the case at hand, the Commission has accepted the stipulated 9.9% rate of return on equity in the context of weighing and balancing numerous factors and making many subjective decisions. When these decisions are viewed as a whole, including the decision to establish the rate of return on equity at 9.9%, the Commission's overall decision fixing rates in this general rate case results in lower rates to consumers in the existing economic environment.

Consumers pay rates, a charge in cents per kWh or per kW for the electricity they consume. Investors are compensated by earning a return on the capital they invest in the business. Consumers do not pay a rate of return on equity. Investors are paid in dollars. In this case, DEC filed rate schedules that would have produced additional annual revenues of $612,647,000. This is the amount ratepayers would pay. These additional revenues, pursuant to the Application and according to DEC's initial calculations, would have produced $5,340,499,000 in total electric operating revenues and $1,093,549,000 in return on investment. Of this amount, $786,153,000 was the return that would have been paid to equity investors, the "return on equity." According to the Application, the "rate of return on equity" financed portion of the investment (as distinguished from the "return on equity") would have been 10.75%.

All of the scores of adjustments the Commission approves reduce the revenues to be recovered from ratepayers and the return to be paid to equity investors. Some adjustments reduce the authorized rate of return on investment financed by equity investors. The noted adjustments are made solely to reduce rates and provide rate stability to consumers (and return to equity investors) to recognize the difficulty for consumers to pay in the current economic environment. While the equity investor's cost was calculated by resort to a rate of return on equity of 9.9% instead of 10.75%, this is only one approved adjustment that reduced ratepayer responsibility and equity investor reward. Many other adjustments reduced the dollars the investors actually have the opportunity to receive. Therefore, nearly all of these other adjustments reduce ratepayer responsibility and equity investor returns in compliance with the Commission's responsibility to establish rates as low as reasonably permissible without transgressing constitutional constraints.

For example, to the extent the Commission makes downward adjustments to rate base, or disallows test year expenses, or increases test year revenues, or reduces the equity capital structure component, the Commission reduces the rates consumers pay during the future period when rates will be in effect. Because the utility's investors' compensation for the provision of service to consumers takes the form of return on investment, downward adjustments to rate base or disallowances of test year expenses or increases to test year revenues, or reduction in the equity capital structure component, reduce investors' return on investment irrespective of its determination of rate of return on equity.

The rate base, expenses, and revenue examples listed above are instances where the Commission makes decisions in each general rate case, including the present case, that influence the Commission's determination on rate of return on equity and cost of service and the revenue requirement. The Commission always endeavors to comply with the North Carolina Supreme Court's requirements that it "fix rates as low as may be reasonably consistent" with U.S. Constitutional requirements irrespective of economic conditions in which ratepayers find themselves. While compliance with these requirements may have been implicit and, the Commission reasonably assumed, self-evident as shown above, the Commission makes them explicit in this case to comply with the Supreme Court requirements of Cooper I.

Based on the changing economic conditions and their effects on DEC's customers, the Commission recognizes the financial difficulty that adjustments in DEC's rates may create for some of DEC's customers, especially low-income customers. As shown by the evidence, relatively small changes in the rate of return on equity have a substantial impact on a utility's base rates. Therefore, the Commission has carefully considered the changing economic conditions and their effects on DEC's customers in reaching its decision regarding DEC's approved rate of return on equity. The Commission also recognizes that the Company is investing significant sums in generation, transmission, and distribution improvements to serve its customers, thus requiring the Company to maintain its creditworthiness in order to compete for large sums of capital on reasonable terms. The Commission must weigh the impact of changing economic conditions on DEC's customers against the benefits that those customers derive from the Company's ability to provide safe, adequate, and reliable electric service. Safe, adequate, and reliable electric service is essential to the well-being of the people, businesses, institutions, and economy of North Carolina.

The Commission finds and concludes that these investments by the Company provide significant benefits to all of DEC's customers. The Commission concludes that the rate of return on equity approved by the Commission in this proceeding appropriately balances the benefits received by DEC's customers from DEC's provision of safe, adequate, and reliable electric service in support of the well-being of the people, businesses, institutions, and economy of North Carolina with the difficulties that some of DEC's customers will experience in paying DEC's adjusted rates.

Finally, the Commission gives significant weight to the Stipulation and the benefits that it provides to DEC's customers, which the Commission is obliged to consider as an independent piece of evidence under the Supreme Court's holdings in CUCA I and CUCA II.

The Commission in every case seeks to comply with the N.C. Supreme Court mandate that the Commission establish rates as low as possible within Constitutional limits. The scores of adjustments the Commission approves in this case comply with that mandate. Nearly all of them reduced the requested return on equity and benefit consumers' ability to pay their bills in this economic environment.

In this case, DEC originally requested a retail revenue increase of $611 million, or a 12.8% increase in annual revenues. The Commission has examined the Company's Application and supporting testimony and exhibits and Form E-1 filings seeking to justify this increase. The Public Staff and DEC reached a Stipulation that resulted in reducing the retail revenue increase sought by the Company by approximately $159 million. The Public Staff represents the using and consuming public, including those having difficulty paying their bills. The Public Staff representatives attended all of the hearings held across the State to receive customers' testimony. The Public Staff has a staff of expert engineers, economists, and accountants who investigate and audit the Company's filings. The Public Staff must recommend rates consumers should pay and the return on investment equity investors should receive. The Public Staff considers all factors included in cost of service. In recent years, the Public Staff and the utilities have entered into settlements resolving the issues so as to avoid at least part of the substantial rate case expense customers otherwise would pay. This process is favored by financial analysts and rating agencies because it reduces delay and enhances predictability, thereby creating a constructive, credit supportive, regulatory environment ultimately reflected favorably in investors' required cost of capital. Intervenors who generally represent narrow segments or classes of ratepayers seldom enter into these settlements, though often times they do not oppose them.

As with all settlement agreements, each party to the Stipulation gained some benefits that it deemed important and gave some concessions for those benefits. Based on DEC's Application and pre-filed testimony, it is apparent that the Stipulation ties the 9.9% rate of return on equity to substantial concessions the Company made.

Summary and Conclusions on the Rate of Return on Equity

The Commission has carefully evaluated the return on equity testimonies of DEC witness Hevert, Public Staff witness Parcell, AGO witness Woolridge, CUCA witness O'Donnell, Commercial Group witnesses Chriss and Rosa, Tech Group witness Strunk, and CIGFUR III witness Phillips. The Commission finds that the comparable earnings analysis testimony of Public Staff witness Parcell, the risk premium analysis testimony of DEC witness Hevert, the comparable earnings testimony of CUCA witness O'Donnell, and the Stipulation are credible, probative, and are entitled to substantial weight.

Public Staff witness Parcell conducted a comparable earnings analysis using both his and witness Hevert's proxy groups of electric utilities. His comparable earnings recommended rate of return on equity range was 9.0% to 10.0%. The Commission approved rate of return on equity of 9.9% is in the upper portion of his range. As testified by witness Parcell, the comparable earnings analysis is based on the opportunity cost principle and is consistent with and derived from the Bluefield and Hope decisions of the U.S. Supreme Court, which are recognized as the primary standards for the establishment of a fair rate of return for a regulated public utility. The comparable earnings method is also consistent with the concept of rate base regulation for utilities, which employs the book value of both rate base and the capital financing rate base. Witness Parcell testified that his comparable earnings analyses considers the recent historic and prospective rates of return on equity for the groups of proxy utilities companies utilized by himself and DEC witness Hevert. He testified that his comparable earnings analyses reflect the actual rates of return on equity of the proxy companies, as well as the market-to-book ratios of these companies.

DEC competes against the Hevert and Parcell electric proxy group electric companies and other electric utilities for investments in equity capital. Investors have choices as to which electric utilities, or other companies, in which to invest. A Commission approved rate of return on equity for DEC below the earned rates of return on equity of other electric utilities could provide one basis for investors to invest in the equity of electric utilities other than DEC.

DEC witness Hevert's risk premium analysis is credible, probative, and entitled to substantial weight. His risk premium was calculated as the difference between the authorized rate of return on equity and the then-prevailing level of long-term 30-year Treasury yield. He then gathered data for 1,508 electric utility rate proceedings between January 1980 and March 31, 2017. The Commission approved rate of return on equity of 9.9% is approximately ten basis points below witness Hevert's risk premium's implied rate of return on equity range of 9.97% to 10.33%.

The Commission also concludes that the comparable earnings analysis by CUCA witness O'Donnell is credible, probative, and entitled to substantial weight. Witness O'Donnell testified that the comparable earnings for his and witness Hevert's proxy group of electric utilities produced earned returns of 9.25% to 10.25% over the period 2015 through 2022, balancing historical and forecasted returns. The Commission-approved 9.9% rate of return on equity is well within that range.

In its post-hearing brief, the AGO argues that the rate of return in the Settlement unnecessarily adds well over $100 million to DEC's annual revenue requirement, compared to an 8.75% rate of return on equity and a capital structure containing 50% equity and 50% debt. The AGO states that such an excessive return sends dollars out of North Carolina to DEC's shareholders – wherever in the world they are – and those dollars would be better spent in our local communities. In addition, the AGO believes that if DEC is allowed to recover coal ash costs from ratepayers drawing on the Commission's discretionary authority for the benefit of DEC's investors, the Commission should also exercise its discretion on behalf of consumers and establish a substantial reduction in the rate of return. The AGO notes that its witness Woolridge initially recommended a rate of return on equity of 8.4% based on market conditions when he prepared his testimony in January of 2018, but increased his recommendation to 8.75% when he updated his analyses two months later in March.

The AGO states that witness Woolridge's recommendation was based on two well-established models, the DCF and CAPM. The AGO argues that the comparable earnings model, which was used by Public Staff witness Parcell and CUCA witness O'Donnell, is not a recognized approach to estimating the cost of equity and that the "Risk Bond Yield Premium" was flawed for the reasons described in the testimony of its witness Woolridge.

The AGO states that ratepayers need a break, particularly if the Commission intends to allow DEC to recover coal ash closure costs.

In its post-hearing brief, the Commercial Group argues that the Settlement rate of return on equity of 9.90% should serve as an upper limit, but only if the Grid Rider mechanism is not approved. If the Grid Rider is adopted, the Commercial Group believes that DEC's rate of return on equity should be set below 9.90%.

CUCA, in its post-hearing brief, recommends that the Commission should not approve the Settlement, including cost of capital issues, between DEC and the Public Staff. CUCA states that the witnesses of the Public Staff, the AGO, CUCA and the Tech Customers have a "clustered" set of rate of return on equity recommendations that center around 9.0%, while DEC's witness recommends 10.75%. CUCA then argues that the 9.9% rate of return on equity in the Stipulation should be rejected, among other reasons, for the fact that it gives equal weight to the recommendations of the Public Staff and DEC witnesses only and gives zero weight to the recommendations of the other three expert witnesses. Further, to the extent that the Commission allows what DEC has requested with regard to coal ash cost recovery, the federal income tax reduction, Power Forward, and the Grid Rider, each of these things makes DEC a significantly less risky investment and, when risks go down, the rate of equity should go down accordingly. CUCA requests that the Commission refuse to accept 9.9% rate of return in the Stipulation and fix a rate of return for DEC that is compatible with the consensus results of the non-DEC witnesses.

In its post-hearing brief, Tech Customers state that while the Stipulation is material evidence entitled to appropriate weight in determining DEC's rate of return on equity and other rate of return inputs, the return approved by the Commission must be justified by substantial, competent evidence in the record as a whole. Tech Customers acknowledge that the 9.9% rate of return agreed to in the Stipulation is comfortably within the range advocated by the parties to the Stipulation, but argues that the Stipulation, standing alone, cannot support the 9.9% recommended return on equity, particularly when the rate at one side of the range lacks any indicia of a rational basis.

Tech Customers state that a utility advocating a rate of return on equity figure that substantially exceeds the output of widely-recognized empirical models and that exceeds recently authorized returns must justify that proposed upward adjustment with a quantitative analysis that shows the applicants risk profile to be materially higher than that of the proxy group. Tech Customers state that its witness Strunk outlined several empirical measures of risk in his testimony and the associated exhibits and none suggests DEC presents a higher risk profile than the proxy group companies. Given the results of the empirical models and the lack of objective evidence by DEC that it presents a higher risk profile than the proxy group warranting an upward departure from these measures, a rate of return on equity of 9.9% is unreasonably high. Accordingly, Tech Customers contend that the evidence presented concerning other authorized rates of return on equity, when put into proper context, lends substantial support to an authorized rate of return on equity of 9.70%.

The Commission has carefully evaluated the DCF analysis recommendations of witnesses Parcell, Hevert, Woolridge, Strunk, and O'Donnell, and the Commission gives limited weight to these analyses. As shown on Commercial Group's Exhibit CR-3, the lowest Commission-approved rate of return on equity for a vertically-integrated electric company for the period of 2015 through 2017 was 9.1%. Witness Parcell's specific DCF result was 8.7%, as stated in AGO witness Woolridge's Supplemental Exhibit JRW-2, p.1, his DCF recommendation was 8.80%, and the mid-point of witness O'Donnell's DCF was 8.5%. The average of Hevert's constant growth DCF means, as stated in Table 11 of his rebuttal testimony, was 8.45%, and the mid-point of the range of witness Hevert's Multi-Stage DCF analysis was 8.78%. The Commission considers all of these DCF results to be outliers, being well below the lowest vertically-integrated authorized rate of return on equity of 9.1%. The Commission determines that all of these DCF analyses in the current market produce unrealistically low results.

The Commission gives no weight to any of the witnesses' CAPM analyses. The analyses of witness Parcell with a mid-point of 6.5% is unrealistically low, and witness Parcell agreed as much in his testimony. The CAPM analysis of witness O'Donnell resulted in a CAPM rate of return on equity mid-point of 6.29%, which is an outlier well below the 9.1% previously discussed. Witness Woolridge's CAPM weighted median rate of return on equity of 7.90% is also an outlier and unrealistically low. DEC Witness Hevert's CAPM range of 9.18% to 11.88% is also an outlier and upwardly biased due to witness Hevert's risk premium component of his CAPM using a constant growth DCF for the S&P 500 companies solely using analysts projected EPS forecasts as the growth component. Witness Hevert's DCF dividend growth, component based solely on analysts' EPS growth projections, without consideration of any historical results, is upwardly biased and unreliable.

The rate of return on equity testimonies of Commercial Group witnesses Chriss and Rosa focused on the commission-approved rates of return on equity authorized for vertically-integrated electric utilities in 2015, 2016, and 2017 listed in Commercial Group Exhibit CR-3. The Commission gives weight to this testimony only as a check on the Commission's approved 9.9% rate of return on equity and to evaluate outlier rate of return on equity recommendations. CIGFUR III witness Phillips' testimony focused on the RRA report Major Rate Case Decisions, which showed a 9.61% average authorized rate of return on equity for electric utilities including both vertically-integrated electric utilities and distribution-only electric utilities. Since DEC is a vertically-integrated electric utility, the Commission gives witness Phillips' rate of return on equity testimony limited weight regarding authorized rates of return on equity for distribution-only electric utilities. Rather, as stated in Commercial Group Exhibit CR-3, recently authorized rates of return on equity for vertically-integrated electric utilities since 2015 average 9.78%, and in jurisdictions with RRA rated Average 1 constructive regulatory environments, being the same A1 rating as North Carolina, as shown in Hevert Exhibit RBH-R27 for the 16 decisions for vertically integrated electric utilities in the years 2015, 2016, and 2017, the average approved rate of return on equity was 9.93%. These two vertically-integrated electric utilities averages serve as a better check.

The 9.9% rate of return on equity approved in this proceeding for DEC is also consistent with the 9.9% rate of return on equity that the Commission approved for DNCP in the 2016 Rate Order and DEP in the 2018 Rate Order.

The Commission notes further that its approval of a rate of return on equity at the level of 9.9% – or for that matter, at any level – is not a guarantee to the Company that it will earn a rate of return on equity at that level. Rather, as North Carolina law requires, setting the rate of return on equity at this level merely affords DEC the opportunity to achieve such a return. The Commission finds and concludes, based upon all the evidence presented, that the rate of return on equity provided for herein will indeed afford the Company the opportunity to earn a reasonable and sufficient return for its shareholders, while at the same time producing rates that are just and reasonable to its customers.

Capital Structure

DEC originally proposed using a capital structure of 53% members' equity and 47% long-term debt. Tr. Vol. 4, p. 43. The Stipulation provides for a capital structure of 52% equity and 48% long-term debt. For the reasons set forth herein, the Commission finds that a 52/48 capital structure as set out in the Stipulation is just and reasonable.

Witness De May testified that the Company's specific debt/equity ratio will vary over time, depending on the timing and size of debt issuances, seasonality of earnings, and dividend payments to the parent company. Tr. Vol. 4, p. 43. As of the end of the test year, the actual regulatory capital structure[14] was 52.8% equity and 47.2% debt, id. at 72, and the 13-month average equity ratio was 54.8%. Id. The 13-month average equity ratio maintained by DEC through November 2017 was 53.3%. Id. The 52/48 capital structure agreed to in the Stipulation represents a compromise between the Company's 53/47 position and the Public Staff's recommendation of a 50/50 capital structure. Both Public Staff witness Parcell and DEC witness De May supported the agreed upon 52/48 capital structure ratios. Tr. Vol. 26, p. 894. DEC witness De May testified that the 52/48 capital structure ratios reflect a reasonable compromise, and also incorporate a reduction from the Company's currently authorized 53/47 capital structure ratios. Tr. Vol. 4, p. 88. Witness Hevert's settlement testimony also supported the stipulated 52/48 capital structure and he stated that the stipulated capital structure is reasonable when viewed in the context of the overall Settlement, and would be positively viewed by the ratings agencies that set the Company's credit ratings. Tr. Vol 4, p. 426. CUCA witness O'Donnell and AGO witness Woolridge recommended that the Commission reject the Company's capital structure proposal and instead advocate a 50/50 hypothetical capital structure. To support their recommended 50/50 capital structure ratios, CUCA witness O'Donnell and AGO witness Woolridge compared DEC's capital structure proposal to either the average common equity ratio of the comparable groups used by the witnesses to determine the recommended return on equity, the capital structure of Duke Energy Corporation, the parent holding company of DEC, or the average common equity ratio authorized by state commissions in regulatory proceedings in 2017.

In rebuttal testimony, DEC witnesses De May and Hevert pointed out that the comparable groups used by each of the witnesses include several parent holding companies with regulated operating company electric utility subsidiaries. Noting that DEC is a utility operating company subsidiary, witness De May testified that it is an inappropriate comparison to include holding companies, i.e., an apples-to-oranges comparison. The Commission has previously commented on and rejected the use of parent company capital structures as opposed to operating company capital structures in determining the operating utility's appropriate equity/debt ratio. (See Order Granting General Rate Increase and Approving Amended Stipulation, Docket No. E-7, Sub 909, pp. 27-28) (December 7, 2009) (2009 DEC Rate Order). Parent and utility operating companies simply do not necessarily have the same capital structures, because, as witness Hevert points out, financing at each level is driven by the specific risks and funding requirements associated with their individual operations. Tr. Vol. 4, p. 287. In addition, witness Hevert notes that the use of the operating subsidiary's actual capital structure – that is, the capital actually funding the utility operations that provide service to customers – is entirely consistent with precedent of the Federal Energy Regulatory Commission (FERC), so long as three criteria are met: the operating subsidiary (1) issues its own debt without guarantees; (2) has its own bond rating; and (3) has a capital structure within the range of capital structures for comparable utilities. Tr. Vol. 4, pp. 287-88. DEC issues its own debt and is rated separately from its parent company, and since the evidence presented by witnesses Hevert and De May shows the DECs

[14] Regulatory capital structure excludes short-term debt and losses on unregulated subsidiaries.

capital structure is generally comparable to that of other operating companies, especially vertically integrated electric utilities, the Commission notes that all three criteria are met. For example, in his rebuttal testimony, witness De May presented the capital structures of four large operating electric utilities located in the southeastern United States at December 31, 2013-16, and at the end of the third quarter of 2017. The averages for these four utilities, Florida Power & Light, Virginia Electric & Power, South Carolina Electric and Gas, and Georgia Power, were 60.7%, 52.9%, 51.4%, and 50.8%. Excluding the highest, Florida Power & Light, the average of the remaining three is 51.7% common equity. Id. at 63. Further, as witness De May testified, for the same reason it is inappropriate to use a proxy group including holding companies, it is inappropriate to apply the capital structure of Duke Energy Corporation to DEC. Id. at 77.

In addition, in the 2013 DEC Rate Case, the AGO argued that a 50/50 capital structure should be implemented for DEC, but, like witness Woolridge in this case, provided "no probative or persuasive evidence suggesting that a 50/50 capital structure is in fact appropriate." 2013 DEC Rate Order, p. 52. The Commission rejected the AGO's argument because that argument did not "recognize the pitfalls were the Commission to order in this case a capital structure at odds with the structure supported by the testimony of the expert witnesses and in line with the Company's actual capital structure in recent years." Id. at 53.

Those pitfalls are readily apparent. First, as witness De May stated, "a 50/50 capital structure would place pressure on…[the Company's "A" level credit rating] by affecting DEC's credit metrics. It would also likely negatively impact the ratings agencies' assessment of qualitative factors, in that movement away from the optimum 53/47 capital structure will likely be viewed as a step away from a credit supportive regulatory environment." Tr. Vol. 4, p. 76.[15] Second, as the Commission has already held in this case in connection with its rate of return on equity discussion, the ratings agencies' "assessment of qualitative factors" is vitally important to the maintenance of the Company's credit quality and to the cost of capital:

> The utilities the Commission regulates compete in a market to raise capital. Financial analysts, rating agencies, and investors themselves scrutinize with great care the regulatory environment and decisions in which these utilities operate. The regulatory environment includes the utilities commissions, consumer advocates, the state legislature, the executive branch and the appellate courts. When regulatory risk is high, the cost of capital goes up.

2013 DEC Rate Order, p. 37 (emphasis added).

[15] Witness De May indicated in his Settlement Testimony that the slight move away from the 53/47 proposed capital structure represented by the Stipulation would likely still be viewed as credit supportive by the ratings agencies. Tr. Vol. 4, p. 84. In any event, a 50/50 structure is a far cry from a 52/48 structure – each percentage point of reduction in equity represents a $10 million reduction in revenue requirement, which is certainly significant in evaluating the effect of further reduction on the Company's credit metrics.

As noted above, CUCA witness O'Donnell also compared DEC's proposed capital structure to the average common equity ratio granted by state commissions in regulatory proceedings in 2017. Based upon such data from SNL, this average common equity ratio was 49.1%. DEC witness Hevert testified in rebuttal that when he excluded proceedings for distribution-only utilities, since DEC is a vertically-integrated electric utility, and excluded proceedings in jurisdictions such as Michigan, Indiana, and Arkansas, that unlike North Carolina, include non-investor supplied sources of capital or use "fair value" rate base in determining a ratemaking capital structure, the authorized equity ratios ranged from 40.25% to 58.18% and the average authorized equity ratio was 50.51%. Tr. Vol. 4, pp. 389-90.

In its brief, the AGO contends that the evidence does not support the need for a capital structure that funds rate base using more than 50% common equity and the excessive reliance on equity in DEC's capital structure will cost ratepayers millions of dollars a year unnecessarily. The AGO states that the high equity ratio of DEC – which is maintained between 52-53% equity – helps to lift up the consolidated capital structure of Duke Energy Corporation. The AGO notes that DEC has the highest secured credit ratings of any of Duke Energy Corporation's subsidiaries and is rated higher than most electric utilities. Thus, the high quality ratio maintained by DEC has obvious benefits for Duke Energy Corporation – particularly in ratings by Standard & Poor's, where consolidated entities are evaluated as a family of risk and assigned a family rating. However, the AGO states that the issue is whether maintaining such a high equity ratio is cost effective for DEC ratepayers. The Commission notes that higher credit ratings translate to lower borrowing costs that certainly benefit ratepayers.

CUCA's brief states that DEC witnesses arrived at a very "equity rich" position of capital structure, recommending that DEC be granted an equity ratio, for ratemaking purposes of 54%. All of the other "expert" witnesses proposed some form of a "pro forma" capital structure closer to 50/50. CUCA pointed out that the cost of equity is higher than debt. Thus, the higher the equity ratio authorized by the Commission, the higher rates that have to be set and paid by customers to support this additional equity element in the capital structure.

In addition to its analysis of witness testimony as set out above, the Commission also gives weight to the Stipulation and the benefits that it provides to DEC's customers, which the Commission is obliged to consider as an independent piece of evidence under the Supreme Court's holdings in CUCA I and CUCA II. As with all settlement agreements, each party to the Stipulation gained some benefits that it deemed important and gave some concessions for those benefits. Based on DEC's Application and pre-filed testimony, it is apparent that the Stipulation ties the 52/48 capital structure to substantial concessions the Company made to reduce its revenue requirement and to alleviate the impact of the rate adjustment on customers.

Finally, the Commission has also carefully considered changing economic conditions in connection with its capital structure determination, including their effect upon the Company's customers. As discussed in the rate of return on equity section above, which is incorporated herein, the public witnesses in this case provided extensive testimony concerning economic stress they are currently experiencing and have experienced for the last several years. The Commission accepts as credible and probative this testimony. Likewise, the Commission gives significant weight to the testimony of witness De May regarding the Company's need to raise capital at this time to finance the improvements needed for safe, adequate, and reliable electric service.

As in the case of the return on equity, the Commission recognizes the financial difficulty that the adjustment in DEC's rates may create for some of DEC's customers, especially low-income customers. The Commission must weigh this impact against the benefits that DEC's customers derive from DEC's ability to provide safe, adequate, and reliable electric service. Safe, adequate, and reliable electric service is essential to support the well-being of the people, businesses, institutions, and economy of North Carolina. The improvements to the Company's system are expensive, but provide tangible benefits to all of the Company's customers. The Commission concludes that the 52/48 capital structure approved by the Commission in this case appropriately balances the benefits received by customers with the costs to be borne by customers, including higher rates which some customers will find difficult to pay.

Accordingly, the Commission finds and concludes that the recommended capital structure of 52% common equity and 48% long-term debt is just and reasonable to all parties in light of all the evidence presented.

<u>Cost of Debt</u>

In its Application and supporting testimony, the Company proposed a long-term debt cost of 4.74%. Tr. Vol. 4, p. 46. The Stipulation provides for a 4.59% cost of debt. The Commission finds for the reasons set forth herein that 4.59% cost of debt is just and reasonable.

In his pre-filed direct testimony, Company witness De May testified that the Company's revenue requirement was determined using an embedded cost of long-term debt of 4.74% at the end of the test year. Tr. Vol. 4, p. 78.

In pre-filed direct testimony, Public Staff witness Parcell did not use the Company's cost of debt in his analysis. Instead, he used 4.57%, which, he testified, was DEC's "actual embedded cost of debt following the issuance of new long-term debt in November of 2017." Tr. Vol. 26, p. 838.

In his rebuttal testimony, witness De May testified that the Company did not agree with moving from the test year to a cost of debt through November 2017. Instead, the Company recommended that the cost of debt be updated through December 2017, which equaled 4.59%. Tr. Vol. 4, p. 78.

In his testimony in support of the Settlement, Public Staff witness Parcell agreed with the embedded cost of debt at 4.59%.

No intervenor offered any evidence to contradict the use of 4.59% as the cost of debt. The Commission therefore finds and concludes that the use of a debt cost of 4.59% is just and reasonable to all parties in light of all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

The evidence supporting this finding and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, the Stipulation, and the entire record in this proceeding.

The Stipulating Parties reached a partial settlement with respect to some of the revenue requirement issues presented by the Company's Application, including those arising from the supplemental and rebuttal testimonies and exhibits. As discussed above, the revenue requirement effect of the Stipulation is shown in Boswell Third Supplemental, as well as Stipulation Exhibit 1 Corrected and Revised McManeus Stipulation Exhibit 1 - Updated for Post-Hearing Issues, which provides sufficient support for the annual revenue required on the issues agreed to in this Stipulation.[16] Section III of the Stipulation outlines a number of accounting adjustments to which the Stipulating Parties have agreed. Public Staff witness Boswell presented schedules showing the financial impact of the Stipulation, as well as the amount of the rate increase that would result if the Commission agrees with the Company on all of the unresolved items, or, alternatively, agrees with the Public Staff on all of these items. The accounting adjustments that are not specifically addressed in other findings and conclusions are discussed in more detail below.

Aviation Expenses

In its initial and revised supplemental filing, the Company removed 39.93% of the Company's O&M costs related to corporate aviation. Public Staff witness Boswell made a further adjustment after investigating the aviation expenses charged to DEC during the test year. 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 DEC staff. The Public Staff recommended that certain expenses allocated to DEC be removed due to the nature of the flights involved. Tr. Vol. 26 p 591-92. For the purposes of settlement, the parties agreed to an adjustment that removes 50% of the Company's corporate aviation O&M expense.

[16] The Stipulation provides that no Stipulating Party waives any right to assert a position in any future proceeding or docket before the Commission or in any court, as the adjustments agreed to in the Stipulation are strictly for purposes of compromise and are intended to show a rational basis for reaching the agreed-upon revenue requirement without either party conceding any specific adjustment. The Stipulating Parties also agreed that settlement on these issues will not be used as a rationale for future arguments on contested issues brought before the Commission.

Executive and Incentive Compensation

In its Application, the Company removed 50% of the compensation of the four Duke Energy executives with the highest level of compensation allocated to DEC during the Test Period. Witness McManeus explained that while the Company believes these costs are reasonable, prudent, and appropriate to recover from customers, DEC has, for purposes of this case, made an adjustment to this item. Tr. Vol. 6, p. 253.

Public Staff witness Boswell recommended removal of 50% of the compensation for a fifth executive, as well as 50% of the benefits associated with the top five executives. Tr. Vol. 26, p. 587. She explained that executive compensation and benefits should be excluded because these executives' duties are closely linked to shareholder interests. Id. at 587-88. Witness Boswell also recommended disallowance of incentive compensation related to earnings per share (EPS) and total shareholder return (TSR). Id. at 590-91. She asserted that incentive compensation tied to EPS and TSR metrics should be excluded because it provides a direct benefit to shareholders only, rather than to customers. Id. at 591.

In his rebuttal testimony, Company witness Silinski testified that these proposed adjustments are inappropriate and should be rejected by the Commission. Tr. Vol. 26, p. 241. Witness Silinski explained that witness Boswell erroneously assumes a divergence of interests between shareholders and customers that has not been demonstrated to exist. Id. at 249. According to witness Silinski, to the contrary, employee compensation and incentives tied to metrics such as EPS and TSR benefit customers because those metrics reflect how employees' contributions translate into overall financial performance. Id. He testified that EPS, for example, is a measure of the Company's performance, and that performance is reflective of how certain goals – safety, individual performance, team performance, and customer satisfaction (all of which are components of incentive pay) are met in a cost-effective way. Id. Divorcing employee performance from such an important measure of a rate regulated company's overall health is unreasonable and counterproductive. Id. Additionally, witness Silinski explained that in order to attract a well-qualified and well-led workforce, the Company must compete in the marketplace to obtain the services of these employees. Id. at 250. The recommended adjustments would render the Company's compensation uncompetitive with the market, resulting in the inability to attract and retain the talent the Company needs to run a safe and reliable electric system. Id. at 246. Finally, witness Silinski pointed out that no witness in this proceeding challenges the reasonableness of the level of compensation expenses reflected in the ratemaking test period for the Company. Id. at 250. The Stipulation provides that "[t]he Company accepts the Public Staff's proposed adjustment to executive compensation to remove 50% of the compensation for the five Duke Energy executives with the highest amounts of compensation, and to remove 50% of the benefits associated with those five executives." Stipulation, § III.E.

As part of the Stipulation, the parties agreed to accept the Public Staff's adjustment with a modification to limit the incentives removed. This agreement is reflected in Section III.H. of the Stipulation, which provides that the Company's employee incentives should be adjusted to remove the cost of the STIP based on the Company's EPS for employees who qualify for the Company's LTIP.

Outside Services

Witness Boswell testified that the Public Staff reviewed costs for outside services associated with expenses that were indirectly charged to DEC by DEBS as well as those incurred by the Company directly that were incurred during the test period. Tr. Vol. 26, p. 592. Public Staff witness Boswell stated that the Public Staff's investigation revealed charges that were related to legal services for coal ash and groundwater issues related to coal ash. Id. She recommended removing these expenses from O&M in the test period. Id. Witness Boswell noted that the Public Staff also found certain expenses that were allocated to DEC that should have been directly assigned to other jurisdictions that she recommended should be removed. Id. at 592-93.

In her rebuttal testimony, witness McManeus noted that the Company agrees with approximately $665,000 of the $2,124,000 adjustment proposed by the Public Staff. Tr. Vol. 6, p. 307. She explained that the portion of the adjustment that the Company opposes is primarily related to legal services related to coal ash and groundwater issues, because the Company takes the position that these costs were reasonable and prudent and, therefore, should be recovered from customers. Id. Pursuant to Section III.F of the Stipulation, the Company agreed to remove certain costs associated with outside services, as stated in its rebuttal filing. This amount does not include costs incurred for certain legal services related to coal ash, which remain in the Unresolved Issues.

Costs to Achieve Duke Energy-Piedmont Merger

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 and Piedmont. Ordering paragraph 7(b) of the Merger Order, which addresses the ratemaking treatment of costs incurred to achieve the merger, states:

> 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, 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.

(Emphasis added).

During the test year in this case, DEC included in operating expenses approximately $6.5 million on a North Carolina retail basis that it identified as systems and transition costs to achieve merger savings. Tr. Vol. 26, p. 594. Witness Boswell contended that the Merger Order only allows the Company to recover the capital costs associated with achieving merger savings, such as system integration costs. Id. As such, the Public Staff removed the $6.5 million of O&M expenses that DEC identified as systems and transition costs to achieve merger savings.

In her rebuttal testimony, witness McManeus explained that the Company opposed this adjustment. Tr. Vol. 6, p. 326. She noted that the costs that witness Boswell has removed are operating expenses, not capital costs. Id. According to witness McManeus, the Merger Order does not specifically address cost recovery for operating expenses associated with achieving merger savings. Id. Witness McManeus explained that should the Commission decide to exclude these expenses from recovery in this case, a deferral order would allow the Company to treat these costs like capital for ratemaking purposes. Id.

Notwithstanding their differing positions on the costs to achieve the Duke Energy-Piedmont merger, in the spirit of settlement and in the context of the Stipulation as a whole, the Company and the Public Staff have resolved this issue. Accordingly, the Stipulation provides that the Company accepts the Public Staff's proposed adjustment to remove costs to achieve the Duke Energy-Piedmont merger.

Sponsorships and Donations

Public Staff witness Boswell adjusted the Company's O&M Expenses to remove amounts paid for sponsorships and charitable donations. Specifically, she excluded from expenses amounts paid to the U.S. Chamber of Commerce, other chambers of commerce, the NC Chamber Foundation, and political-related donations. Tr. Vol. 26, p. 599. Witness Boswell argued that these expenses should be disallowed because they do not represent actual costs of providing electric service to customers. Tr. Vol. 26, p. 599. In her rebuttal testimony, witness McManeus testified that Chambers of Commerce promote business and economic development which in turn helps to retain and attract customers to DEC's service territory. Tr. Vol. 6, p. 311. She explained that funds paid to Chambers of Commerce that are not specified as a donation or lobbying on the Chamber invoice are generally assumed to be in support of business or economic development and are considered to be properly charged as a utility operating expense that should be included in the Company's cost of providing electric service to customers. Id. at 311-12. As a result, the Company opposed a portion of witness Boswell's proposed adjustment. Id. at 12. Witness McManeus also noted that in reviewing the adjustment proposed by witness Boswell, the Company determined that $5,261 of the charges in question were reclassified during the test period to FERC Account 426, which is excluded from cost of service. Id. Pursuant to Section III.K of the Stipulation, the Public Staff agreed to accept the Company's rebuttal position on sponsorships and donations expense, which removed amounts paid to the U.S. Chamber of Commerce and certain other expenses.

Lobbying and Board of Director Expenses

Witness Boswell made an adjustment to remove 50% of the expenses associated with the Board of Directors of Duke Energy that have been allocated to DEC. Tr. Vol. 26, p. 589. She argued that the Board of Directors has a fiduciary duty to protect the interests of shareholders, which may differ from the interests of ratepayers. Id. Accordingly, the Public Staff believes it is appropriate for the shareholders of the larger electric utilities to bear a reasonable share of the costs of compensating the Board of Directors, as well as the cost of insurance for these individuals. Id. Witness Silinski explained that the Company is required to have a Board of Directors and that the costs of being an investor-owned utility, including Board costs, are in fact costs of service. Id. at 252. He argued that it is not fair or reasonable to penalize the Company for being an investor-owned utility with attendant requirements to that corporate structure. Id. at 252-53.

With respect to lobbying expenses, witness Boswell noted that the Company made an adjustment to remove some lobbying expenses from the test year. Tr. Vol. 26, p. 595. She further adjusted O&M expenses to remove what she characterized as additional lobbying costs, including O&M expenses that she believed were associated with stakeholder engagement, state government affairs, and federal affairs that were recorded above the line. Id. at 595-96. In her rebuttal testimony, witness McManeus explained why the Company opposed this adjustment and disagreed with witness Boswell's characterization of these expenses. Tr. Vol. 6, p. 327. Witness McManeus testified that in 2016, the Company engaged a third-party consulting company to perform a detailed time study for the purposes of determining the percentage of time certain individuals spent on lobbying activities per the federal definition in 29 Code of Federal Regulations Section 367.4264. Id. A report with the results of the study was delivered to the Company in August 2016, and the Company booked journal entries to ensure that the 2016 labor costs were aligned with the results of the independent study. Id. Witness McManeus concluded that no further adjustments were warranted. Id.

Nevertheless, in the spirit of settlement and in the context of the Stipulation as a whole, the Company and the Public Staff have resolved these issues, and in Section III.K. of the Stipulation, the Company agreed to accept the Public Staff's recommended adjustments to lobbying and Board of Directors' expenses.

Allocations by DEBS to DEC

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. As discussed above, during the test year, Duke Energy acquired Piedmont and the Commission approved the merger on September 29, 2016. According to Public Staff witness Boswell, this change, along with updates related to other affiliated entities, has caused the DEC allocation factors to decrease. Tr. Vol. 26, p. 595. Witness Boswell made an adjustment to reflect the fact that O&M expenses allocated to DEC from DEBS will be less going forward. Id. In her rebuttal testimony, witness McManeus explained that the Company did not agree with witness Boswell's adjustment because she included only three months of costs related to Piedmont, which results in a mismatch between the allocation factors and the costs to which they are being applied. Tr. Vol. 6, 323. In her supplemental testimony, witness Boswell updated the adjustment to include a full 12 months of the impact of the Piedmont acquisition into the adjustment and noted that the Company did not oppose this adjustment. Tr. Vol. 6, p. 617. As part of settlement, the parties agreed to accept the Public Staff's adjustment regarding the DEBS to DEC allocation as set forth in the supplemental testimony of Public Staff witness Boswell. Stipulation, § III.M.

Salaries and Wages

In her direct testimony and schedules, Company witness McManeus included an adjustment to annualize and normalize O&M labor expenses to reflect annual levels of costs as of April 1, 2017. The adjustment also restated variable short and long term pay to the target level. Tr. Vol. 6 p. 262. This adjustment was further updated in her supplemental filings. In her supplemental testimony, Witness Boswell explained that she adjusted the Company's updated payroll to reflect annualized payroll through December 31, 2017. Tr. Vol. 26, p. 616. For DEBS payroll allocated to DEC she applied the updated allocation factor only to the increase in payroll between December 31, 2016 and December 31, 2017, as the test year amount is included in the DEBS to DEC allocation adjustment discussed above. See id. She noted that the Company does not oppose this adjustment, as updated in witness Boswell's second supplemental filing. Id. The Stipulation provides that the Company accepts the Public Staff's methodology as to how to calculate salaries and wages as set forth in the supplemental testimony of witness Boswell. Stipulation, § III.N. Boswell Third Supplemental and Stipulation Exhibit 1 Corrected and McManeus Revised Stipulation Exhibit 1 – Updated for Post-Hearing Issues update the salaries and wages adjustment to reflect the Company and Public Staff's resolution on how to quantify the agreement reached in Section III.N of the Stipulation.

Upon consideration of all of the evidence in this proceeding, including the Stipulation which the Commission accepts in its entirety and upon which the Commission places great weight, the Commission finds and concludes that the stipulated adjustments discussed herein are just and reasonable to all parties and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

The evidence supporting this finding of fact and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, the Company and Public Staff Agreement and Stipulation of Partial Settlement, and the entire record in this proceeding.

In this case, the Company included an adjustment to amortize the excess deferred state income taxes that it deferred pursuant to the Commission's May 13, 2014 Order in Docket No. M-100, Sub 138. In its Application, the Company proposed that the State EDIT liability included in this case be returned to customers over a five-year period. Tr. Vol. 6, p. 263. Public Staff witness Boswell testified that it would be beneficial to return the State EDIT to customers through a rider that would expire at the end of a two-year period. Tr. Vol. 26, p. 600.

In the Stipulation, the parties agreed that the State EDIT liability should be returned to customers through a levelized rider that will expire at the end of a four-year period. Stipulation, § III.B. The Stipulating Parties provide that the appropriate level of State EDIT to be refunded to customers is $60,102,000 annually for the four years following the effective date of the rates approved in this proceeding. See Boswell Second Supplemental and Stipulation Exhibit 1; see also Revised McManeus Stipulation Exhibit 1 – Updated for Hearing. No intervenor took issue with this provision of the Stipulation. Accordingly, the Commission finds and concludes that the four-year State EDIT rider as set forth in Section III.B of the Stipulation is just and reasonable to all parties in light of all the evidence presented, and is hereby approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

The evidence supporting this finding of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

In its Application, the Company requested recovery of certain operations and maintenance O&M expenses associated with its Customer Connect project. Company witness Hunsicker testified about the Company's plans to replace its customer information system (CIS), a project known as "Customer Connect," and the costs and revenue requirement the Company is seeking in this case to support this project. Tr. Vol. 18, pp. 253-64, 281. Witness Hunsicker explained that the Company's current CIS was developed over 20 years ago and was not designed to efficiently support new capabilities. Id. at 257. She stated that the Company and its customers' needs are very different than they were when the original CIS was constructed, and the system is past the point where modular "bolt on" systems or modular upgrades are effective. Id. at 255. Additionally, the Company's current CIS has many deficiencies. For example, the Company's existing CIS is not equipped to handle complex billing arrangements, such as net metering for self-generating customers, and these bills must be manually calculated. Id. at 257-58. The current CIS also does not enable access to account histories nor does it allow customers to employ preferred communication methods. Id. at 258-59. Witness Hunsicker explained that the new CIS will provide universal and simplified processes for customers, improve billing, allow the Company to easily identify and implement new rate structures for customers, and interface with the Company's new AMI technology. Id. at 261. Witness Hunsicker explained that Customer Connect began analysis and design in January 2018, and is currently planned to be in-service for DEC in 2022. Id. at 262. She further explained that the implementation will be phased and that new capabilities will be available to customers each year leading up to full deployment. Id. at 263. The estimated costs for Customer Connect for DEC, North Carolina, is between $220 and $230 million, which is based on the best and final offers for fixed price contracts that the Company negotiated with the software, systems integration, and change management vendors. Id. at 263. Witness Hunsicker explains that the Company is seeking a pro forma adjustment from $4.4 million to $15.1 million in O&M expenses associated with the project to reflect the average expected annual O&M expenses associated with the project from 2018 through 2020. Id. at 264.

Public Staff witness Floyd testified regarding the Public Staff's support of DEC's Customer Connect project. Tr. Vol. 23, p. 80. Witness Floyd described the shortcomings of the Company's current CIS and the improvements offered by the new CIS. Id. at 77-80. He also described the implementation plan for Customer Connect and recommended that the Company make semi-annual reports on the status of the implementation. Id. at 80, 82-83.

Witness Floyd further testified that the $13.3 million of expense related to the Company's initial work on Customer Connect is reasonable. Id. at 83. However, he also testified that Customer Connect was not used and useful as of the test year ending December 31, 2016, and that the full capabilities of Customer Connect will not be realized until the summer of 2022. Id. at 81. Therefore, the Public Staff, through witness Boswell, recommended an adjustment to remove from the Company's revenue requirement, the Customer Connect amounts projected for 2018 through the in-service date, reasoning that the system will not be fully functional until the summer of 2022. Tr. Vol. 26, p. 597.

In her rebuttal testimony, Company witness Hunsicker responded to the Public Staff's recommendation to remove the forecasted amounts of O&M expense between 2018 and the in-service date for Customer Connect. Tr. Vol. 18, p. 266. She explained that the Company has only asked for the level of O&M necessary to deploy the capital for the program, and that DEC is not asking for the program or its costs to be placed into rate base. Id. at 268. These O&M costs are not being capitalized to the program, and in order to be captured, they either need to be included in rates as the Company has requested, or set aside and capitalized to a regulatory asset to be recovered when the project comes online. Id.

Company witness Fountain explained that by entering into the Stipulation, the Company agreed to accept the Public Staff's adjustment to Customer Connect expenses, and the Company shall be authorized to establish a regulatory asset to defer and amortize expenses associated with its Customer Connect project. Tr. Vol. 6, pp. 219-20. Company witness McManeus explained that the Company shall be allowed to accrue a return on the regulatory asset in the same manner that Construction Work in Progress (CWIP) balances accrue AFUDC. Id. at 350. Company witness McManeus explained that AFUDC shall end and a 15-year amortization shall begin on the date Releases 5-8 of the project goes into service or January 1, 2023, whichever is sooner. Id.

Additionally, in order to provide the Commission and other interested parties with information concerning the status of development, spending, and the accomplishments to date, the Stipulating Parties will develop the reporting format and the content of that report within 90 days of the Commission's order approving the Stipulation, with the reports to be filed in this docket for the next five years by December 31 of each year or until Customer Connect is fully implemented, whichever is later. Stipulation, Section III.C.

In its post-hearing Brief, NCSEA cites the testimony of DEC witness Fountain that AMI and DEC's new CIS, Customer Connect, are interlocking components; and contends that if properly implemented together the two systems can provide customers with access to their energy consumption data to enable them to effectively conserve electricity. NCSEA states that it is generally supportive of DEC's investments in AMI and Customer Connect, but that DEC must ensure that Customer Connect can provide customers with energy consumption and allow customers to easily authorize third parties to access such data. NCSEA submits that DEC has failed to show that AMI and Customer Connect will provide these customer benefits. Citing the testimony of DEC witness Hunsicker, NCSEA contends that despite recognizing the benefit of providing consumers with access to their energy consumption data, investing in technology capable of providing consumers such access, and having no issue with providing consumers such access, DEC is not doing so. NCSEA acknowledges that the Commission has directed DEC to meet with NCSEA and other stakeholders to discuss implementing the Green Button Connect protocol for access to energy consumption data, but, nonetheless, submits that DEC has not provided sufficient evidence in this docket that Customer Connect will meet customer needs, comply with industry standards, or is capable of complying with directives from this Commission. As a result, NCSEA asserts that DEC's request for cost recovery for Customer Connect should be denied at this time.

Upon consideration of all of the evidence in this proceeding, including the Stipulation, the Commission approves the stipulated adjustments to the Company's Customer Connect expenses in this proceeding, and the Company shall be authorized to establish a regulatory asset to defer and amortize expenses associated with its Customer Connect project. The Commission finds that an effectively designed and implemented Customer Connect project may provide value to DEC's customers and support continued quality of service.

In arriving at its conclusion, the Commission gives substantial weight to the testimony of witness Hunsicker and witness Floyd regarding the deficiencies with the Company's current CIS and the improvements and new functionalities that the modernized CIS will provide to customers through implementation of the Customer Connect program. Thus, it is appropriate that these costs be deferred and allowed to accrue until the time that Customer Connect goes in-service or by January 1, 2023. Witnesses Hunsicker and Floyd have also testified to the benefits that customers will receive from the Customer Connect program in stages throughout its implementation. The Commission notes that the Company and Public Staff will file with the Commission a proposed Customer Connect reporting format and the content of that report within 90 days of this Order, and that subsequent reports shall be filed annually for the next five years, or until implementation is complete. The reporting will allow the Commission to monitor the status of the Customer Connect project and the associated expenses throughout the implementation process. The Commission recognizes the data access concerns expressed by NCSEA and determines that it is appropriate for the Customer Connect annual report to clearly describe the status of efforts to effectively provide energy consumption data to customers and the precautions taken to ensure data remains secure.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 23-24

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony, exhibits, and affidavits of DEC witnesses Fountain, McManeus and Miller, and Public Staff witness Boswell, and the entire record in this proceeding.

In its Application, the Company requested that its capital investment in the Lee CC plant, approximately $557 million, be included in rate base. DEC witness Miller explained that the Lee CC plant was expected to begin commercial operation in November 2017, provide 750 megawatts (MW) of total capacity, and emit carbon dioxide at half the rate and nitrogen and sulfur oxide emissions at a fraction of the rate compared to the plants retired by the Company. Tr. Vol. 26, p. 212. In her testimony, Public Staff witness Boswell proposed the removal of the Company's estimated O&M expenses needed to operate the plant as it represented an estimate, not actual O&M expenses needed to operate the plant. Id. at 580. Additionally, witness Boswell testified that if the Lee CC plant was not in service by the close of the hearing, she recommended removing the plant and related deferral adjustments from rates and including the plant in CWIP to be included in rate base. Id. at 581.

In her second supplemental testimony, Company witness McManeus reduced the amount of estimated incremental O&M costs associated with the Lee CC facility to approximately $1.98 million. Tr. Vol. 18, p. 296. Witness Miller testified that while the Lee CC plant was not yet in service, the Company utilized the actual non-labor O&M expenses for two substantially similar combined cycle plants, Buck and Dan River, to calculate the estimated incremental O&M expenses for Lee CC. Id. at 236. Therefore, according to witness Miller, the Buck and Dan River facilities serve as a reasonable proxy to determine whether the Company's estimated O&M expenses for Lee CC are reasonable. Id. In her supplemental testimony, Public Staff witness Boswell proposed to include a displacement adjustment to reflect the fact that existing plant(s) in the Company's fleet may not run as frequently due to the availability of the new plant. Tr. Vol. 26, p. 620. In his rebuttal testimony, DEC witness Miller stated that a displacement adjustment was not appropriate because Lee CC was built to serve a growing number of customers and the associated growth of energy and peak demand requirements. Id. at 235.

As part of the Settlement, the Public Staff and DEC agreed that for purposes of settlement, DEC would withdraw its adjustment to include incremental O&M expenses and the Public Staff would withdraw its displacement adjustment. Stipulation, § III.L. The Stipulating Parties therefore agreed that the appropriate level of ongoing O&M expense to be included in rates is $0. Id. The Stipulating Parties also agreed that the appropriate amortization period for the deferred expenses associated with the Lee CC facility is four years. Id. Additionally, DEC and the Public Staff agreed that it was appropriate to hold the record open until March 23, 2018, to allow the Company to submit final cost amounts to be included in this proceeding for Lee CC and for Public Staff to use these amounts to file with the Commission the Stipulating Parties' final recommendation with regard to the Lee CC-related revenue requirement, including Lee CC deferred costs, using the methodology recommended by the Public Staff in this proceeding. Id. Further, DEC and the Public Staff agreed to hold the record open to allow the filing by the Company of an affidavit indicating that the plant has closed to service for operational and accounting purposes and that it is used and useful for the benefit of customers. Id.

In accordance with the Stipulation, DEC provided the Public Staff with the final costs of the Lee CC plant on March 23, 2018. On April 10, 2018, the Public Staff filed its updated recommendations regarding Lee CC plant and expense-related items, as shown in Boswell Third Supplemental and Stipulation Exhibit 1. Also on April 10, 2018, the Company filed the Affidavit of Joseph A. Miller, Jr. indicating that as of April 5, 2018, the Lee CC plant closed to service for operational and accounting purposes and is providing DEC with 650 MW of capacity for the benefit of its North and South Carolina customers. On April 19, 2018, the Company filed Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues, which, among other things, reflects updates to the Lee CC plant and expense-related items to reflect final costing information for inclusion in this proceeding, including updates to plant investment, related deferred income taxes, depreciation, materials and supplies, and the deferral of those costs between the plant's operation date and the date rates are expected to become effective. On April 19, 2018, the Public Staff filed Boswell Third Supplemental and Stipulation Exhibit 1 Corrected, which, among other things, corrects the Lee CC addition to plant in service and corrects the Lee CC deferral calculation.

No intervenor took issues with these provisions of the Stipulation. Upon consideration of all of the evidence in this proceeding, including the Stipulation, which the Commission accepts in its entirety and upon which the Commission places great weight, the Commission finds and concludes that it was appropriate to keep the record open to allow the Company the additional time to attest to the commercial operation of the Lee CC facility and the Stipulating Parties to resolve the final cost amount to be included for recovery in this proceeding. The Commission appreciates the Stipulating Parties working together to resolve this matter economically. Because the conditions of the Stipulation have been met in a timely and appropriate manner, the Commission finds and concludes that DEC's request to recover the final cost amounts included in this case for the Lee CC plant, as adjusted by the Stipulating Parties and reflected in Boswell Third Supplemental and Stipulation Exhibit 1 Corrected and Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues, is just and reasonable to all parties in light of all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence supporting this finding and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

In her direct testimony, Company witness McGee testified to the Company's position that the beneficial reuse of coal ash constitutes a sale of by-product produced in the generation process, and therefore, associated gains and losses on the sale should be included in the fuel adjustment clause under N.C. Gen. Stat. § 62-133.2(a1)(9). Tr. Vol. 26, pp. 195-97. She explained that the Company excluded net loss amounts for

September 2017 through August 2018, related to the sale of coal ash produced at the Company's Riverbend coal plant, from its March 8, 2017 fuel filing, pending the Commission decision in this proceeding. Id.

Public Staff witness Lucas testified that the costs relating to the disposal of coal ash from Riverbend to the Brickhaven facility in Chatham County, North Carolina, to the extent they are reasonable and prudent, should be recovered in base rates and not through the fuel adjustment clause because such costs did not result from sale of coal ash.

In Section III. P of the Stipulation, DEC withdrew its request to recover certain CCR costs through the fuel adjustment clause related to the excavation and movement of CCRs from Riverbend to Brickhaven. The Stipulation also provides that the recovery of these costs are left in the Company's deferred CCR balance for consideration of recovery in the Company's base rates.

No intervenor contested these provisions of the Stipulation. Accordingly, the Commission finds and concludes that the provisions of the Stipulation regarding the consideration of recovery of certain CCR costs through base rates, rather than fuel, as set forth in Section III.P of the Stipulation are just and reasonable to all parties in light of all the evidence presented, for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

The evidence supporting this finding and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Company witness McGee also testified with respect to the amount of fuel that should be included in base rates. In her direct testimony she testified that she supported the fuel component of proposed base rates for all customer classes and the fuel pro forma adjustments to the test year operating expenses contained in McManeus Exhibit 1. Tr. Vol. 26, pp. 191-92. Witness McGee proposed to use the total prospective fuel and fuel-related costs factors that DEC proposed on March 8, 2017 in Docket No. E-7, Sub 1129. Id. Witness McGee explained that DEC's intent in using the fuel-related factors that were proposed at the time the Company's Application was prepared as a component of its proposed new rates was to make it clear that the Company is requesting a rate increase that relates to non-fuel revenues only. Id. at 194. In her testimony, Public Staff witness Boswell recommended that the base fuel and fuel-related cost factors be updated to reflect the rates that were actually approved by the Commission in that docket. Tr. Vol. 26, p. 584. In her rebuttal testimony, Company witness McManeus stated that the Company did not oppose the Public Staff's recommendation. Tr. Vol. 6, p. 305. Accordingly, Section IV. B. of the Stipulation sets forth the Stipulating Parties' agreed upon total of the approved base fuel and fuel related cost factors, by customer class, as set forth below (amounts are ¢/kWh excluding regulatory fee):

- Residential 1.7828 cents per kWh
- General Service/Lighting 1.9163 cents per kWh
- Industrial 2.0207 cents per kWh

Tr. Vol. 6, p. 354.

According to witness McGee, the Company will continue to bill customers the fuel rates authorized by the Commission in its annual fuel proceedings. Tr. Vol. 26, p. 194. As such, there will be no change in customers' bills as a result of including these fuel cost factors in the proposed base rates. Id. As shown on Boswell Third Supplemental and Stipulation Exhibit 1, Schedule 3-1(t), the Company's North Carolina retail adjusted fuel and fuel-related costs expense for the Test Period was $1,082,899,000. This amount was calculated using the base fuel factors identified above and North Carolina retail test period actual kWh sales by customer class as adjusted for weather and customer growth. Tr. Vol. 26, p. 193.

No intervenor contested these provisions of the Stipulation. Accordingly, the Commission finds and concludes that the provisions of the Stipulation regarding the base fuel and fuel-related cost factors as set forth in Section IV.B of the Stipulation are just and reasonable to all parties in light of all the evidence presented, for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 27

The evidence supporting this finding and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

The Company's proposed adjustment for coal inventory, as reflected in its Form E-1, Item 10, Adjustment NC-1600, set the inventory balance to 40 days of 100% full load burn, resulting in a reduction to the materials and supplies component of cash working capital in this case. Tr. Vol. 23, p. 18. This is the level of coal inventory that was used in DEC's last general rate case for the materials and supplies component of cash working capital and was stipulated to by the Public Staff and the Company in the settlement agreement approved by the Commission in that case. Id.

In his pre-filed testimony, Public Staff witness Metz recommended adjusting the materials and supplies component of cash working capital to reflect a 40-day coal inventory based on a 70% full load burn. Id. at 25. He testified that a 70% capacity factor represents a reasonable estimate of the Company's coal fleet performance during peak conditions, though he would expect that the Company would adjust its inventory based on anticipated seasonal needs. Id. at 25-26. Witness Metz based his recommendation on DEC's historical trends and predicted use of the Company's coal fleet, as well as DEC's lower delivered fuel prices due to closer proximity to coal sources, combined with the efficiency of the Company's coal generation technology. Id. at 27.

In his rebuttal testimony, Company witness Miller explained that the Company actually contemplated requesting an increase in the full load burn inventory target to enable the Company to respond to un-forecasted increases in coal generation demand, given the increased volatility in coal generation due to factors such as fluctuating natural gas prices and weather-driven demand. Tr. Vol. 26, p. 228. However, the Company determined that it was prudent to continue to operate under the current 40-day full load burn inventory target and made a pro forma adjustment reducing its actual coal inventory at the end of the Test Period to reflect this. Id.

Witness Miller testified that adopting witness Metz's recommendation of a 40-day coal inventory based on a 70% full load burn could lead to negative supply, delivery, and operational impacts. Id. at 228-29. He testified further that his recommendation fails to contemplate the factors that impact a reliable fuel supply, including volatility in coal generation demand, delivery and/or supply risks, and generation performance. Id. at 228-29. In particular, he noted that witness Metz's recommendation assumes there will be ample amounts of coal available during higher demand periods and does not contemplate the increased demand from other utilities during the same period of increased demand being experienced by the Company. Id. at 228-31. Witness Miller explained that a 40-day, 70% capacity factor equates to only a 28-day full load burn at 100% during periods of peak demand. Id. at 228. According to witness Miller, if DEC is unable to dispatch cost-competitive coal generation during peak demand due to unreliable inventory levels, it will have to seek alternatives such as dispatching higher cost generation, paying higher prices for fuel, or purchase power. Id. As such, having unreliable coal inventory levels could result in unfavorable impacts on customers. Id. at 229.

In the Stipulation, the Public Staff and DEC agreed that for purposes of settlement, the Company may set carrying costs included in base rates reflecting a 35-day coal inventory at 100% capacity factor, and that a coal inventory rider should be allowed to manage the transition. More specifically, the Stipulating Parties propose that this increment rider shall be effective on the same date as new base rates approved in this proceeding and continuing until inventory levels reach a 35-day supply to allow the Company to recover the additional costs of carrying coal inventory in excess of a 35-day supply (priced at $73.23 per ton). The rider will terminate the earlier of (a) May 31, 2020 or (b) the last day of the month in which the Company's actual coal inventory levels return to a 35-day supply on a sustained basis.[17] The Stipulation provides that for this purpose, three consecutive months of total coal inventory of 37 days or below will constitute a sustained basis. The Company will adjust this rider annually, concurrent with DEC's DSM/EE Rider, REPS Rider, and Fuel Adjustment Rider, and any over- or under-collection of costs experienced as a result of this rider shall be reconciled in that annual

[17] The Stipulation provides that the Company reserves the right to request an extension of the May 31, 2020 date.

rider proceeding. Additionally, the Stipulation provides that any interest on any under- or over-collection shall be set at the Company's net-of-tax overall rate of return, as approved by the Commission in this proceeding. Finally, the Company agreed to conduct an analysis in consultation with the Public Staff demonstrating the appropriate coal inventory level given market and generation changes since the Company's last rate case (Docket No. E-7, Sub 1026), with such analysis to be completed by March 31, 2019.

No intervenor took issues with this provision of the Stipulation. The Commission finds and concludes that the reduction to coal inventory included in working capital and the establishment of the increment rider to allow the Company to recover the additional costs of carrying coal inventory in excess of a 35-day supply, as provided in the Stipulation, is just and reasonable to all parties in light of all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 28

The evidence supporting this finding of fact and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Summer Coincident Peak

DEC based its filing in this case on the summer coincident peak (SCP) methodology for allocation of the cost of service among jurisdictions and among customer classes. The Public Staff, CIGFUR III, CUCA, and Kroger concur with DEC's use of the SCP methodology for cost allocation. No intervenors presented testimony in opposition to the Company's use of the SCP methodology for cost allocation. Moreover, the Stipulation provides for the use of the SCP methodology for purposes of settlement.

Company witness Hager testified in support of the SCP methodology for allocation among jurisdictions and among customer classes. She explained that a coincident peak allocator assigns the fixed demand-related costs to the jurisdictions and customer classes in proportion to their respective contribution to the system's maximum hourly demand during the test period. Tr. Vol. 19, pp. 24-25.

Each jurisdiction's and customer class' cost responsibility (i.e. the percentage of the fixed portion of production and transmission demand costs assigned to each jurisdiction and customer class) is equal to the ratio of their respective demand in relation to the total demand placed on the system. Id. at 25. The cost of service study supporting the Company's proposed rate design in this proceeding allocates the fixed portion of production and transmission demand-related costs based upon a jurisdiction's and customer class' coincident peak responsibility occurring during the summer. Id.

DEC's peak system demand for the test year, occurred on July 27, 2016, at the hour ending at 5:00 p.m. Id. This was also the peak generation and transmission demand used in the Company's cost of service study for the test year. Id. Witness Hager explained that the SCP in the test year is within the range of previous SCP occurrences, and it is therefore appropriate to assign fixed demand-related costs to the Company's jurisdictions and customer classes based upon the SCP. Id. at 26.

The Public Staff agreed with the Company's use of the SCP cost of service methodology. The Stipulation reflects that the "Public Staff does not oppose the Company's cost of service study and allocation methodology for purposes of settlement in this case only, with the exception of coal ash costs, which is included within the Unresolved Issues" (Stipulation, § III.C) and separately addressed herein at Finding and Conclusion No. 28. Public Staff witness Floyd explained that the Public Staff has historically supported and continues to support, the Summer Winter Peak and Average (SWPA) methodology. Tr. Vol. 23, p. 54. The Public Staff, however, does not object to the Company's use of the SCP, for purposes of this proceeding, because the differences between the per books calculations of revenue requirement between the SCP and SWPA methodologies is immaterial on a jurisdictional basis. Id. at 55.

CUCA witness O'Donnell agreed that the SCP allocation methodology "is appropriate for use in the Company's cost of service study in this proceeding." Tr. Vol. 18, p. 117. Witness O'Donnell stated that since DEC's system is historically summer peaking, the SCP cost of service study "is the most representative model of how the generation system is used in any given year." Id. at 116.

CIGFUR III witness Phillips also agreed that the SCP allocation methodology "is appropriate for use in the Company's cost of service study in this proceeding." Tr. Vol. 26, p. 257. Witness Phillips testified that the SCP allocation methodology "properly allocates cost responsibility to customer classes and, if rates are designed consistent with cost of service, minimizes the need for new generating capacity consistent with DEC's load management goals by sending correct price signals." Id. Kroger also supports the use of the SCP allocation methodology, and witness Higgins testified that the method "allocates production demand and transmission costs to jurisdictions and customer classes based on each group's contribution to the system's highest peak demand, which has historically occurred in summer months." Tr. Vol. 4, p. 500.

The Commission finds and concludes that SCP is the appropriate cost allocation methodology for purposes of this proceeding, subject to the provisions of the Stipulation. Upon consideration of all of the evidence in this proceeding, including the Stipulation upon which the Commission places significant weight, the Commission approves use of the SCP cost allocation methodology to set the Company's base rates in this proceeding.

In arriving at its conclusion, the Commission finds that having the necessary generation and transmission resources to meet the Company's summer peak (plus an appropriate reserve margin) is an essential planning criteria of the Company's system. Under cost causation principles, therefore, all customer classes should share equitably in the fixed production and transmission costs of the system in relation to the demands they place on the system at the peak. As discussed and supported in DEC's integrated resource plans, the Commission also recognizes the Company's shift to winter capacity planning. This change will require more attention in the Company's next general rate case. The Kroger Co. in its post-hearing Brief stated that "[i]f the Commission determines that the winter peak should also be considered in the allocation of production demand costs, an allocator based on the average of the single highest summer and single highest winter coincident peaks may also be appropriate." See Post-Hearing Brief of the Kroger Co., p. 7. The Commission concludes that DEC should file annual cost of service studies based on Winter Coincident Peak as well as the SCP and SWPA methodologies. In its next general rate case, the Company shall prepare cost of service studies based on each of these methodologies.

Although the Public Staff has traditionally supported the SWPA methodology, it is not unreasonable for the Stipulating Parties to have agreed to the use of SCP in this proceeding. Further, the Commission notes that the difference in the retail revenue requirements between the SCP and SWPA methodologies is immaterial on a jurisdictional basis.

The Commission finds and concludes that, for purposes of this proceeding, the Company may use the SCP methodology for allocation between jurisdictions and among customer classes under the provisions of the Stipulation and that the provisions of the Stipulation regarding cost of service methodology are just and reasonable to all parties in light of all the evidence presented.

Minimum System

The Company used a minimum system study to allocate distribution costs among customer classes. The Public Staff does not oppose the Company's cost of service study and allocation methodology for purposes of settlement. NCSEA witness Barnes objects to the use of a minimum system study to allocate costs to customers. Tr. Vol. 20, pp. 74-95. Moreover, witness Barnes also criticizes the specific methodology used by the Company, which he argues inflates the size and cost of the minimum system and increases the portion of the distribution system classified as customer-related. Tr. Vol. 20, p. 94-95.

Witness Hager explained that DEC's minimum system study allowed DEC to classify the distribution system into the portion that is customer-related (driven by number of customers) and the portion that is demand-related (driven by customer peak demand levels). Tr. Vol. 19, p. 35. The methodology behind the Company's minimum system study allows DEC to assess how much of its distribution system is installed simply to ensure that electricity can be delivered to each customer, regardless of the customer's frequency of use. Id. at 36. Witness Hager testified that "[w]ithout the minimum system, low use customers could easily avoid paying for the infrastructure necessary to provide service to them which is counter to cost causation principles." Id. She further explained that the methodology used by the Company is consistent with the guidance regarding allocation of distribution costs provided in the NARUC Cost of Service Manual. Id. at 37.

Witness Hager also explained that while the NARUC Cost of Service Manual suggests two methods of allocation, both of these methods identify a portion of FERC distribution asset accounts 364 to 368 as customer-related and a portion as demand related. Id. at 38. Therefore, witnesses Barnes' and Wallach's suggestion that all of the costs charges to accounts 364 to 368 should be allocated based on demand is inconsistent with the guidance provided in the NARUC Cost of Service Manual. Id.

On cross-examination by counsel for NCSEA, witness Hager testified regarding the Company's long history of using the minimum system method, stating that "the minimum system study has long been used in the cost of service study to develop the customer-related costs that are then passed to rate design and are the basis of rates that are ultimately approved by the Commission." Id. at 138-39. The Company "filed minimum system study results in every rate case for a long time" and the Commission "has approved the results of that." Id. at 143.

In response to questioning from Commissioner Clodfelter, witness Hager testified about the different variations of the minimum system method used by DEP and DEC. Tr. Vol. 20, pp. 27-29. Witness Hager explained that DEP determines the cost of constructing a minimum system configuration using today's costs and the cost of constructing a standard configuration in today's costs, and applies that ratio to the balance of plant account. Id. at 28. Alternatively, DEC calculates the current cost for a minimum size system and then applies a Handy-Whitman Index to adjust to book costs. Id. at 29. She noted, however, that while the methods differ, "they both have the same ultimate goal" and "get you back to the same place." Id. at 28, 30.

In its post-hearing Brief, NCSEA states that "the minimum system analysis is flawed." See NCSEA's Post-Hearing Brief, p. 37. NCSEA states that the minimum system methodology "assumes that some costs of the shared distribution system are effectively incurred solely for the purpose of connecting each customer and that these costs should therefore be classified as customer-related." Tr. Vol. 20, pp. 75-76. In effect, the minimum system methodology "double counts" demand-related costs because a minimum system is still capable of serving some level of demand. Id. at 76.[18]

Furthermore, NCSEA states that the Company's modified minimum system methodology does not examine actual costs, but rather defines costs for specified components and extrapolates those costs across the Company's system. Id. at 86. In the case of poles and conductors, this results in more items being included in the minimum system study than are actually on the Company's system and results in a negative assignment for these components in the demand charge. Id. at 87. Further, NCSEA states that the Company's modified minimum system methodology contains flaws in its analysis

[18] See also, Tr. Vol. 19, p. 36 ("But if someone, for whatever reason, wants electricity to light a single 100-Watt light bulb, that customer will require distribution assets such as poles and conductors and transformers to deliver that electricity."). NCSEA notes that, while small, a single 100-watt light bulb would nonetheless impose demand on the grid. See also, Official Exhibits, Vol. 20 (NCJC, et al., Hager/Pirro Cross Exhibit 1) ("Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.").

of poles and structures, overhead conductors, line transformers, and service drops. Id. at 90-94.

The Commission is not persuaded by the evidence presented in this docket that the minimum system analysis employed by the Company is flawed in a way that precludes the Commission from accepting it as appropriate for cost allocation in this proceeding. However, the Commission gives some weight to NCSEA witness Barnes' argument that "[t]he Commission should reconsider its past acceptance of this method for the allocation for distribution costs, and disregard the results as a consideration in rate design." Tr. Vol. 20, p. 95. Witness Barnes stated in his testimony that "Many states confine the definition of customer costs to those costs that are directly attributable to a customer, such as metering and billing, excluding portions of the distribution system shared by multiple customers. A report commissioned by the National Association of Regulatory Utility Commissioners (NARUC) found that this basic customer method (100% demand for shared distribution facilities and 100% customer for meters and services) was the most common approach at the time of the report. There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states.[19] Tr. Vol. 20, p. 79.

Further, witness Barnes stated in his testimony that:

> [i]t is not clear to me that the Commission has recently delved into the details of the different methodologies used by North Carolina utilities in conducting their minimum system studies. In fact, significant differences in methodology are apparent to me based on my review of the studies performed by DEP, DEC, and Dominion Energy North Carolina (Dominion). For instance, in its 2016 general rate case, Dominion classified only 31.08% of secondary poles in FERC Account 364 as customer related [in its most recent rate case.][20] DEP classified 95.9% of secondary poles in FERC Account 364 as customer related in its most recent rate case.[21]

Tr. Vol. 20, pp. 82-83.

[19] F. Weston, et al., Charges for Distribution Service: Issues in Rate Design, p. 19, Regulatory Assistance Project (2000), available at http://pubs.narus.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

[20] Application of Virginia Electric and Power Company, d/b/a Dominion North Carolina Power, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, Docket No. E-22, Sub 532 (March 31, 2016) DNCP Form E-1, Item 45F, p. 121.

[21] Duke Energy Progress, LLC's response to NCSEA Data Request No. 10-20, Attachment B, Docket No. E-2, Sub 1142 (detailing customer and demand percentages by FERC Account).

According to witness Barnes, DEC effectively classifies all shared secondary and primary poles in FERC Account 364 (as well as conductors in FERC Account 365) as customer-related. This is visible in the Company's COSS in the form of negative values for demand-related plant in service for FERC Accounts 364 and 365.[22] The negative values arise because the Company's calculated minimum system is larger than the actual FERC Account balance after removing direct assignments, which necessitates an adjustment. The true-up adjustment effectively results in a demand-related component of zero and a customer-related component of 100%. Similar differences are evident for other distribution Accounts, contributing to a wide range of estimates of residential customer units costs. Id.

The Commission recognizes that any approach to classifying costs has virtues and vices. It is important to effectively address issues such as those discussed by witness Barnes while at the same time recognizing the Company's substantial projected investments in its Power Forward programs. Just considering the grid modernization programs alone suggests that distribution system cost allocation among customer classes will take on heightened importance in future rate cases. The implications of using a suboptimal methodology or incorrectly applying an otherwise acceptable methodology, could be significant in the future. The Commission concludes that a more focused and explicit evaluation of options for distribution system cost allocation and an assessment of the extent to which any single allocation methodology is being consistently applied by the utilities is warranted. Therefore, the Commission directs the Public Staff to facilitate discussions with the electric utilities to evaluate and document a basis for continued use of minimum system and to identify specific changes and recommendations as appropriate. If the Public Staff ultimately recommends an alternative approach to minimum system as a result of this review, then the support for that position should be clearly defined. The Public Staff shall submit a report on its findings and recommendations to the Commission no later than the end of the first quarter of 2019 in a new, generic electric utility docket to be established by the Chief Clerk for this purpose.

Upon consideration of all the evidence in this docket, including the Stipulation, the Commission approves DEC's use of the minimum system methodology for cost allocation in this proceeding. The Commission places significant weight on the testimony of Company witness Hager regarding the Company's long history of employing the minimum system method and this method's alignment with cost causation principles. The Commission finds that the Company's use of the minimum system method for cost allocation in this proceeding is just and reasonable to all parties in light of all of the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

The evidence supporting this finding of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony of Public

[22] DEC Form E-1, Item 45D, p. 5.

Staff witness Boswell, the rebuttal testimony of DEC witness Doss, as well as the entire record in this proceeding.

As part of its filing in this case, the Company submitted a lead-lag study that was performed in 2010 using fiscal year 2009 data. Tr. Vol. 12, pp. 50, 55. Public Staff witness Michelle Boswell commented that a fully updated lead-lag study should have been completed for this case, and recommended that the Commission direct the Company to prepare and file a lead-lag study in its next rate case. Tr. Vol. 26, p. 602. In his rebuttal testimony, DEC witness Doss stated that the Company agrees with Public Staff witness Boswell's recommendation and testified that DEC will prepare and file an updated lead-lag study as part of its next rate case application. Tr. Vol. 12, p. 55.

The Stipulation incorporates the Company's agreement to file an updated lead-lag study in its next rate case. Stipulation, § IV.D. No intervenor took issue with this provision of the Stipulation. Accordingly, the Commission finds and concludes that, consistent with Section IV.D of the Stipulation and in light of all the evidence presented, DEC shall prepare and file an updated lead-lag study in its next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 30

The evidence supporting this finding of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Company witness Pirro provided testimony regarding the Company's proposed changes to rate design. Witness Pirro's direct testimony focused on DEC's major proposed rate design initiatives, including:

(1) Basic Facilities Charge (BCF) The Company proposes the BFC for all rate classes, with the exception of OPT-V, be set to recover a percentage difference between the current rate and the customer-related cost incurred to serve these customer groups. Tr. Vol. 19, p. 57. Witness Pirro explained that this approach was taken because current rates significantly understate the current cost of service related to the customer component of cost. Id. The Company's recommendation reduces subsidization while minimizing the rate impact on low usage customers. Id. A comparison of the current and proposed BFCs for each rate class is provided in Pirro Exhibit No. 8.

(2) Residential Rates. Witness Pirro explained that the Company has not proposed any major structural changes to its residential rates. The Company, however, has increased the discount available to customers taking service under Rate RS and Rate RE and receiving Supplemental Security Income through the Social Security Administration and who are blind, disabled, or 65 years of age or over. Id. at 61. The Company also proposes to discontinue Residential Water Heating Service Controlled/Sub Metered Schedule. Id. at 72-73.

(3) General and Industrial Rates. Witness Pirro explained that other than revisions to the rate to collect the revised revenue requirement, the Company has not altered the overall structure of Rate LGS, Rate SGS, and Rate I, service to large general service, small general service, and industrial customers, respectively. Id. at 62. The Company proposes to increase the incremental demand charge for Rate HP to $0.5994 per kW. Id. at 63.

In Section IV.E of the Stipulation, the Stipulating Parties agreed to implement the rate design proposed by Company witness Pirro within in his direct testimony, except for the amount of the BFC which was an unresolved issue and addressed separately in Finding and Conclusion No. 34 herein. Additionally, the Company entered into the Lighting Settlement with NCLM, Concord, Kings Mountain, and Durham, which resolved certain outdoor lighting issues raised by intervenors in this docket. The Public Staff does not object to the Lighting Settlement.

Several intervenors provided testimony on various rate design issues in this proceeding, as discussed below. Having considered the testimony and exhibits of all of the witnesses and the entire record in this proceeding, the Commission makes its findings and conclusions on each of these issues as set forth below:

AMI Enabled Rates

EDF witness Alvarez criticized the lack of detail in the Company's Application regarding time varying rate offerings that the Company plans to implement in conjunction with AMI. Tr. Vol. 26, pp. 321-27. Company witness Pirro responded that "[i]t would be premature to offer a specific rate design before the infrastructure to support the design is available." Tr. Vol. 19, p. 88.

Additionally, EDF witness Alvarez testified about various AMI-enabled services that he argues offer significant customer and environmental benefit potential. See, e.g., Tr. Vol. 26, pp. 322-27. Company Witness Pirro responded that the Company will consider new rate designs after full AMI deployment, which is expected by mid-2019. Tr. Vol. 19, p. 87. As the Company continues deployment of AMI and begins implementation of new billing infrastructures, the Company will evaluate all potential future rate designs, including dynamic rate designs, and will assess the approach or combination of approaches that cost-effectively meets customer interests and demand response objectives. Id. Witness Pirro also responded to witness Alvarez's suggestion that a collaborative would be beneficial in developing time-varying rate designs, by reiterating that the Company highly values customer input in evaluating both current and future rate designs. Id. at 88. He explained that the Company routinely discusses its rate design with members of the Public Staff and customers, and that it is preferable that such input be received on an on-going basis, rather than awaiting a group meeting to be certain this guidance is considered in the decision-making process with respect to future rate designs and requirements for supporting infrastructures. Id.

Witness Pirro further explained why it would be premature to offer a specific AMI-enabled rate design in this proceeding. Id. In addition to the fact the AMI technology and new billing system infrastructure has not been implemented yet, he testified that it is important to evaluate each rate design in conjunction with other demand response options that seek to shift customer consumption. Id. He explained that all customer options need to be evaluated to achieve the most dependable load response at the lowest cost to customers. Id.

Public Staff witness Floyd testified that the Public Staff's support of the Company's AMI deployment is predicated on maximizing benefits to the customers. Tr. Vol. 23, p. 90. Witness Floyd noted that the Company has committed to develop new and innovative rate designs, which should contribute toward maximizing customer benefit. Id.

The Commission agrees that it is premature to offer specific AMI-enabled rate designs in this proceeding since the infrastructure underlying such rate design is not yet available. The Commission concludes, however, that it is appropriate for DEC to evaluate new rate designs that will, among other things, allow ratepayers in all customer classes to use the information provided by AMI to reduce their peak time usage and to save energy.

TOU or Critical Peak Pricing Rates

NCLM witnesses Hunnicutt and Coughlan testified that the Company should provide additional time-of-use (TOU) and critical peak pricing (CPP) dynamic pricing options for customers. Tr. Vol. 8, pp. 119-43; Tr. Vol. 26, p. 373. The City of Durham stated in its post-hearing Brief that it joins with the NCLM to ask the Commission to order DEC to develop proposals for effective time-of-use and critical peak pricing rate designs which encourage energy efficiency, and provide that information to ratepayers as soon as possible. Witness Hunnicutt testified generally that DEC "should find additional ways through its time-of-use rate designs to encourage and incentivize conservation" and "should provide additional data regarding energy usage to . . . customers on time-of-use rate schedules." Tr. Vol. 26, p. 378. Witness Coughlan testified in more detail regarding the Small General Service Time of Use (SGST) rate and CPP rate option studies, the Peak Time Credit (PTC) Rider pilot, and the smart grid project. Tr. Vol. 8, pp. 121-40. Witness Coughlan advocates for the reintroduction of the SGST rate with lower kW and kWh charges, a TOU rate, a CPP rate, a SGS-TOUE rate, the OPT-E rate, and other dynamic pricing options. Id. at 105, 142-43.

Witness Coughlan testified that TOU and CPP dynamic pricing rates can provide a societal benefit. Id. at 119. These rates incent customers to reduce their peak demands and energy consumption during peak periods. Id. This stabilizes demand and creates significant savings for DEC and all customers. Id. While witness Coughlan acknowledged that DEC currently offers the OPT-V rate, he claimed that this TOU rate is not applicable for most customers, who have a load factor of less than 51%. Id. at 120.

Witness Coughlan also discussed the SGST and CPP rates that the Commission ordered the Company to offer on a pilot basis in Docket No. E-7, Sub 1026. Id. at 121-38. Upon conclusion of the pilot period, the Company decided to terminate these rates. Id. at 127. Ninety percent of the customers who participated in the SGST rate pilot program lost money compared to being served on their previous rate. Id. at 128. Witness Coughlan maintained that the SGST rate pilot was unsuccessful because the kW and kWh charges were too high. Id. He argued that if the SGST rate were reintroduced with lower kW and kWh charges, many customers could and would take advantage of the rate. Id. at 129.

DEC, however, terminated the SGST pilot rate, citing "below average acquisition rates and limited performance feedback available to customers." Id. at 127. Customer participation in the SGST pilot rate was low. Id. at 129-30. Witness Coughlan argued that with more time and more marketing efforts, participation would increase. Id. at 130. Moreover, without smart meters available to all customers served by the pilot rates, the Company was not able to provide the rate comparison data that customers wanted. Id. at 130-31; 137-38.

Witness Coughlan asserted that DEC is in a position to implement TOU and CPP rates now, and that municipal jails, parks/recreation facilities, and water and sewer treatment facilities, in particular, could benefit from these pricing options. Id. at 142.

In its post-hearing Brief, NCLM stated that "[t]he Commission should order DEC to develop proposals for new and innovative time-of-use and critical peak pricing rate designs and prepayment options before the next rate case, and receive input from customers." See Post-Hearing Brief and Partial Proposed Order of NCLM, p. 11.

In his direct testimony, Company witness Pirro explained that DEC was not proposing any innovative peak time pricing rate designs or offering real time price signals in this proceeding. Tr. Vol. 19, p. 58. Witness Pirro explained that DEC continues to review and analyze rate designs that offer customers opportunities to respond to price signals to achieve a lower cost for electric service. Id. As described in the testimony of witness Hunsicker, the Company is upgrading its billing system infrastructure to better support these types of designs. Id. Also, as explained by Company witness Schneider, DEC is in the process of deploying AMI that will provide the level of data that is required to bill these innovative designs. Id. at 58-59. Witness Pirro explained that the Rate Design Team is working closely with billing and metering projects to ensure that they will support the types of rate designs that customers will need in the future. Id. at 59. Witness Pirro also noted that the Company presently offers time-of-use rate designs to various customer classes to encourage load shifting and also offers several DSM programs to control customer appliances to aid in reducing system peak demands. Id. Moreover, on cross-examination by counsel for NCLM, witness Pirro explained that as the Company "gets closer to full AMI rollout and implementation of the billing systems, we will continue to work with the Public Staff and try to come to a common . . . ground on future price offerings and trying to balance that with maybe some demand response programs to achieve overall cost effectiveness." Id. at 203.

Based on the results of the pilot rates implemented in Docket No. E-7, Sub 1026, the Commission is not persuaded that DEC should be required to offer any additional TOU or CPP dynamic pricing rate options at this time. However, the Commission finds and concludes that DEC should, within six months of the date of this Order, file in this docket the details of proposed new time-of-use, peak pricing, and other dynamic rate structures, as detailed in the AMI portion of this Order.

OPT-V Rate

CIGFUR III witness Phillips criticized DEC's Optional Power Service Time of Use (OPT-V) rate schedule. Tr. Vol. 26, p. 258. While witness Phillips agreed that the Company's proposed demand charges for the OPT-V rate class were appropriate, he argues that the present and proposed energy rates are significantly higher than the unit costs reflected in DEC's cost of service study. Id. He stated that the energy charges for OPT-V customers are 30-60% above the unit costs in the Company's cost of service study, and argued that these charges should be reduced to better reflect actual energy costs. Id. at 268. Witness Phillips recommended that any approved reduction to the Company's requested revenue increase for the OPT-V class be used to reduce the proposed energy rates, particularly for Transmission Service and Large Primary Service customers. Id.

On cross-examination by counsel for CIGFUR III, witness Pirro explained that the Company did not agree with witness Phillips' recommendation to adjust the OPT-V rate design to move the energy charges closer to unit cost. Tr. Vol. 19, pp. 115-24. Witness Pirro explained that the OPT-V "rate and pricing structure has been very successful from the onset. [DEC has] had very positive feedback from [its] commercial/industrial groups during customer meetings, and they . . . have been very happy with the pricing structure. And . . . during those customer forum groups, [the Company has] had no complaints." Id. at 120. He added that OPT-V is a relatively new rate design and the Company has received positive feedback regarding this rate from both external and internal customers through its large account management and economic development teams. Id. at 124.

In addition to the Company having received very positive customer feedback regarding the OPT-V rate, witness Pirro explained that the Company must "look at all the pricing components in order to send appropriate price signals." Id. at 123. One such factor is marginal cost pricing, and witness Pirro testified that reducing energy rates below those levels would not be justifiable. Id. at 122. He reiterated that it is inappropriate to adjust the energy charge in isolation, and that the Company must "look at all of the pricing components as a whole, the customer charge component, the demand and energy, and you have to balance those to send the appropriate price signal." Id.

The Commission finds and concludes that the Company's proposed OPT-V rate is just and reasonable in light of the evidence presented. The Commission, therefore, rejects witness Phillips' recommendation to reduce the proposed energy rates for Schedule OPT-V on the grounds that adjusting one pricing component without consideration of all pricing factors is inappropriate. It is appropriate to consider all pricing components, including marginal cost pricing, customer charge, as well as demand and energy charge, and balance these various components in order to set rates that send an appropriate price signal to customers. Applying that framework, the Commission finds and concludes that the Company's proposed OPT-V rate, including the proposed energy rate, strikes an appropriate balance of pricing factors and sends the correct price signal to customers.

Outdoor Lighting

Company witness Cowling testified regarding the proposed changes to DEC's outdoor lighting rate schedules. First, the Company re-evaluated the outdoor lighting transition fees charged to customers who move from metal halide (MH) and high pressure sodium (HPS) to light emitting diode (LED). Tr. Vol. 26, p. 161. The Company is proposing to lower the transition fees to balance the actual take-rates while protecting the rate class from premature retirement of assets. Id. Witness Cowling explained that the Company has charged a transition fee for customers who voluntarily chose to upgrade standard, decorative, and/ or floodlight outdoor lighting fixtures from MH or HPS to LED. Id. at 162. The purpose of the transition fee was to appropriately reflect the remaining book value of the MH and HPS lights being replaced and hence slow the early retirement of installed assets to avoid adverse impacts on lighting rate base. Id. While the fees have successfully allowed customers to switch to LED technology while minimizing the impact of the transition on other lighting customers, the Company, based on its transition experience to LED technology, now recommends calculating transition fees based on a revised assumption regarding the rate of replacement of fixtures. Id. at 162-63. DEC proposes to reduce the fee to transition from a standard MH or HPS fixture to an LED fixture from $54 to $40 on Schedules GL and PL, and from $78 to $57 on Schedule OL. Id. at 163. The Company proposes to reduce the fee to transition from a standard MH floodlight or HPS floodlight fixture to an LED and/or LED floodlight fixture on Schedule FL from $142 to $112. Id. Cowling Direct Exhibit 1 outlines the current and proposed transition fees on Schedules OL, GL, PL, and FL.

Second, the Company proposes to proactively replace mercury vapor (MV) lights with LED lights on Schedule PL (governmental customers). Id. at 161. Currently, DEC is authorized to upgrade MV fixtures to LED technology upon failure on Schedule PL. Id. at 165. In Docket No. E-7, Sub 1114, DEC received Commission approval to proactively upgrade standard MV fixtures to LED on Schedule OL (private area lights) by no later than December 31, 2019. Id. at 165-66. Under the current approach of only replacing MV fixtures at failure and assuming that customers do not choose to upgrade voluntarily, at the current failure rate of approximately 4.6% per year it will take approximately 22 years to upgrade all of the MV fixtures in North Carolina. Id. at 166. A proactive strategy allows the Company to more rapidly phase-out obsolete MV fixtures in the DEC service territory. Id. Also, it is more cost-effective for the Company to replace the MV lights proactively grouping the work geographically, rather than reactively one-by-one as they fail. Id. The Company is proposing that the Commission approve DEC's proactive replacement on Schedule PL to begin in 2020 and with work completed by 2023. Id. at 167. This gives governmental customers adequate time to budget for the conversions, and also gives the

Company adequate time to complete the proactive replacement underway on Schedule OL by the current December 2019 goal. Id.

Lastly, the Company is proposing several revisions to the outdoor lighting schedules to improve administration, including proposals (1) to close Schedule NL, which is a pilot tariff designed primarily to introduce LED technology, (2) to discontinue Schedule FL and merge it into Schedules OL and GL, and (3) to increase the contract term on Schedule OL for standard products from one year to three years. Id. at 161, 169-70. The Company incurs a significant capital investment when installing new outdoor lighting assets and these costs are not recovered if lighting service is discontinued after one year. Id. at 169.

Witness Cowling also explained in his direct testimony that the Company has participated in semi-annual meetings to address issues of interest to North Carolina municipalities and to specifically address lighting issues. Id. at 168. The Company states these meetings are valuable and plans to continue the outdoor-lighting specific dialogue that has been established between municipalities and the Company by meeting with the NCLM and governmental customers on as-needed basis. Id. at 168-69.

Public Staff witness Floyd responded to the Company's proposed outdoor lighting schedules by making three recommendations. First, Witness Floyd explained that the Public Staff agrees with DEC's proposed transition fees for LED service, testifying that the fees "reasonably balance the desire of customers for LED service, with the need to transition lighting in an orderly manner, while minimizing the adverse impact of stranded costs on the remaining lighting class." Tr. Vol. 23, p. 68. The Public Staff, however, states that the Company should consider providing an extended payment option to customers, such as municipalities who desire LED service, but struggle with budgeting issues that prevent their participation. Id. at 69.

Second, witness Floyd testified that the Company's proposal to accelerate the conversion of MV fixtures to LED served under Schedules OL and PL is reasonable, but recommends that the Company address the rates of return (ROR) for the lighting class in order to mitigate the increase in the cost of the conversion. Id. at 72. Witness Floyd recommended that the Company reduce its rates for Schedules FL, GL, OL and PL such that the resulting RORs are within 10% of the overall ROR for the North Carolina retail jurisdiction. Id. at 72-73. Witness Floyd also recommended that the Commission require the Company to file semi-annual reports on the status of its MV replacement program. Id. at 73.

Witness Floyd testified that the Public Staff does not object to the Company's proposals to close Schedules FL and NL. Id. at 74. Witness Floyd also testified about the alignment of rates for the same fixtures served under Schedules GL and PL. Id. at 74-76. Witness Floyd noted that Schedule GL and PL charge different rates for the same fixture, and that the only difference between the two schedules is the length of time a customer has been served under one schedule versus the other, which is not a valid reason for differing rates. Id. at 76. As such, he recommends that the Commission require the

Company to continue to meet with municipal customers to evaluate changes to Schedules PL and GL that would make the rates for individual fixtures (LED and non-LED) served under Schedule GL the same as for Schedule PL. Id. at 76-77. He also recommends that the Company work with municipalities to develop a proposal to consolidate Schedules PL and GL in a future proceeding. Id. at 77.

NCLM was the only other intervenor to provide testimony regarding outdoor lighting rate design. NCLM witnesses Coughlan, Fisher and Watkins all presented testimony on various outdoor lighting issues.

Witness Coughlan recommended several changes to the GL rate schedule. Witness Coughlan advocated for the elimination of the transition fees for replacing HPS and MH luminaires with LED luminaires. Tr. Vol. 8, p. 104. Mr. Coughlan noted that the purpose of the transition fee was to appropriately reflect the remaining book value of the MH and HPS lights in order to avoid adverse impacts on the lighting rate base. Id. at 107. However, he argued, that the Company should actively promote the transition to LED lighting rather than discourage it through fees because LEDs are better for customers and the environment. Id. at 108. Witness Coughlan argued that DEC should not be compensated for the transition to new technology. Id. Alternatively, he suggested that DEC could offset the loss in book value by requiring all lighting customers to pay for it, instead of only those customers switching to LED luminaires. Id. at 109.

Witness Coughlan advocated for establishing a fairer rate for municipalities under Rate GL by lowering the proposed rates for LED lighting. Id. at 110. The proposed ROR for Rate GL is 27.23%, compared to 7.98% for total retail rates. Id. at 109. Witness Coughlan noted that, overall LED lighting costs less than HPS lighting (e.g., installation labor costs, maintenance labor costs, maintenance equipment costs, energy costs), but DEC's rates for LED lighting "are significantly higher" than the rates for HPS lighting. Id. at 111-14. He asserted that lower maintenance labor costs, maintenance equipment costs, and energy costs for LED lighting should be, but are not, accurately accounted for in the proposed rates. Id. at 115-16. Witness Coughlan recommended that the costs for lighting under Schedule GL be adjusted such that on a cost/kWh consumed basis, the rates for LED lighting are equal to or lower than the costs of HPS lighting. Id. at 104.

Witness Coughlan also testified that, to the extent the transition fee is not eliminated, the Commission should only apply such a fee where a municipality seeks to convert all HPS lights to LED lights at the same time. Id. at 118. Witness Coughlan recommended eliminating the transition fee where an existing HPS light has failed or needs maintenance. Id. He argued that "[t]his approach would save DEC from having to travel to existing HPS lights to perform maintenance work and then making another trip back to the same light a year or two later to replace a recently maintained HPS light with an LED light as part of a mass conversion." Id.

Similarly, witness Watkins testified that the Company's LED transition fees and outdoor lighting rates make it "difficult for [the City of] Burlington and other municipalities to afford a complete conversion to LED lighting" which inhibits these municipalities from "maximizing energy efficiency and prevent crime." Tr. Vol. 26, p. 390. He recommends that DEC should cover the cost of conversions for HPS and MH fixtures as well as MV fixtures. Id. at 391. Likewise, witness Fischer testified that DEC should eliminate the transition fee entirely. Id. at 367. Furthermore, witness Fischer stated that if DEC decides not to charge a transition fee for LED lighting, the rates attributable to LED fixtures should not increase, as proposed in DEC's PL rate schedule. Id. at 390, 367. Witnesses Watkins and Fischer also recommended that if the municipality is required to pay a transition fee to switch to LED lighting, the rates paid for LED street lighting should not increase. Id. at 390, 368. Witnesses Watkins and Fischer testified that the current transition fees and the requirement to shift from Schedule PL to GL rate for conversions create a disincentive for municipalities to convert to LED street lighting. Id. at 391, 368.

These witnesses also noted that the Company is requesting rates for street lighting with a ROR for the GL class of 27.22% and the PL class of 12.20%, which fall outside of the +/-10% band of reasonableness for RORs relative to overall jurisdictional ROR (7.98%). Id. at 392, 368. Finally, witness Watkins testified that the NCLM would like to continue meeting with the Company semi-annually, rather than on an as needed basis as suggested by witness Cowling. Id. at 393.

In response to the intervenors' testimony regarding the Company's transition fees for LED service, witness Cowling explained in his rebuttal testimony that "the Company believes these fees are appropriate, as the Company, consistent with its Commission-approved tariffs, installed HPS and MH fixtures at the request of customers; thus, the prudently incurred stranded costs related to these assets should be recovered from the customer requesting early replacement, rather than burdening the lighting class as a whole." Id. at 173. He further testified that the Company will continue to monitor net book value and in future rate proceedings and seek adjustments accordingly. Id.

Witness Cowling also testified in opposition to witness Coughlan's recommendation that transition fees be eliminated for any HPS failure. Id. at 174. He explained that as stated in Witness Coughlan's testimony, HPS lamps last approximately six years, which is far less than the HPS fixture. Id. Given the long depreciation periods of HPS fixtures, replacing HPS fixtures after being in service for six years due to a bulb failure without a transition charge would still leave a significant net book value remaining for HPS fixtures. Id.

Witness Cowling agreed with the recommendation of Public Staff witness Floyd, and testified that the Company wants to work with NCLM to evaluate changes to Schedules PL and GL for the purpose of eventually consolidating Schedules PL and GL in a future proceeding. Id. at 177. Witness Cowling also testified that the Company values its partnership with all of the communities it serves and NCLM and will continue to meet with NCLM regarding outdoor lighting matters. Id. at 176. The Company has proposed meeting on an as-needed basis to provide more flexibility to meet either more or less often and address issues in a timelier manner as they arise. Id. at 177. The Company has also expressed an interest in attending NCLM's annual meeting to discuss lighting matters, which would minimize travel costs to NCLM members and expand the opportunity for more municipalities to participate in outdoor lighting discussions with the Company. Id.

Witness Pirro testified in response to the intervenors' testimony regarding the ROR for the lighting rates. Tr. Vol. 19, pp. 97-98. Regarding the proposed ROR of 27.23% on Schedule GL, witness Pirro explained that the proposed rates and concomitant return are the result of the application of the same rate design principles that were applied to all other rates proposed in this proceeding. Id. at 97. As noted on Pirro Exhibit No. 4 the current return on this rate schedule is nearly 31%. Id. DEC seeks to achieve rate parity for all of its customer classes; however, rate parity cannot be achieved quickly without some customers experiencing significant rate increases. Id. Thus, DEC has and is applying the principle of "gradualism" as it moves all rate classes closer to a uniform return. Id. While DEC understands witness Floyd's and NCLM witnesses' concerns, it must be recognized that ratemaking is a zero-sum process and costs not recovered from one customer class must be recovered from another customer class. Id. at 97-98. Witness Pirro testified that "DEC is committed to continuing to work with the Public Staff and NCLM in an attempt to resolve their concerns in a manner that is appropriate for DEC's other customers, and acceptable to the Commission, and will allow DEC a reasonable opportunity to recover its Commission-approved revenue requirement." Id. at 98.

Prior to the evidentiary hearing, the Company entered into the Lighting Settlement with NCLM, Concord, Kings Mountain, and Durham, which resolved all of the outdoor lighting issues raised by the NCLM in this docket.[23] The parties to the Lighting Settlement agreed to waive cross-examination of each other's witnesses on the outdoor lighting issues addressed in the Lighting Settlement. Lighting Settlement, p. 6. Moreover, the Public Staff does not object to the Lighting Settlement, (id. at 2), and waived its cross-examination of Company witness Cowling.

The Lighting Settlement provides in pertinent part as follows:

> 1. DEC shall keep the current proposed LED transition fee reduction for HPS luminaires from $54.00 to $40.00, but will evaluate adoption of LED technology and its impact on the transition fees every two years between rate cases and adjust the fees downward if applicable. DEC will eliminate the HPS transition fee on entire fixture failure. Transition fees will not be increased outside of a general rate proceeding. The results of any re-evaluation will be reported to the Commission and be subject of a filing for a fee reduction.
>
> 2. DEC will allow municipalities to spread the billing for transition fees for up to four years without incurring carrying costs, to be billed annually in August.

[23] The only remaining issues in controversy raised by NCLM in this docket are (1) the impact of the Tax Cuts and Jobs Act on DEC's rates; and (2) TOU and CPP dynamic pricing rate options.

3. DEC will combine Rate Schedule GL (Governmental Lighting) and Rate Schedule PL (Street and Public Lighting) to reflect PL pricing as approved by the Commission in its final order in this Docket, effective September 1, 2018 and close Rate Schedule GL. Lights on Schedule GL will be mapped to the rates proposed on PL for inside municipal limits. For Schedule GL lights served underground, DEC will apply underground charges assuming up to 200 feet served from overhead to underground for a monthly fee of $0.87 per month. Additional decorative and/or non-standard charges for poles, fixtures, or underground fees greater than 200 feet will still apply as would be applicable under the currently-identical provision of Schedules GL and PL. This will lower the ROR on the GL rate.

4. Combining Rate Schedule GL and Rate Schedule PL and not seeking an increase in LED rates in this Docket results in a $1.658 million revenue requirement deficit to DEC. Upon approval by the Commission, the lighting ROR will be reduced to fall within the +/-10% range of the retail average and the resulting revenue reduction ($1.658 million under proposed rates) would be allocated to the other rate classes (RES, GS, I and OPT). The Parties affirm that this Agreement reflects the spirit and intent to continue moving government lighting’s ROR closer to the average retail customer ROR.

5. DEC will maintain current LED prices for GL and PL customers and not seek a rate increase for LED fixtures in this Docket. After September 1, 2018, all LED rates applicable to governmental customers will be billed on the PL schedule.

6. For all customer lighting classes, DEC will eliminate the HP’S transition fee if the entire HPS fixture fails. Upon complete fixture failure, unless no comparable LED fixture is available, DEC will replace any standard or non-standard and/or decorative HPS fixture with a comparable LED fixture and the monthly rate for the new fixture will apply. DEC will continue to maintain HPS fixtures and perform minor repairs. DEC will not waive the transition fee for HPS fixtures that are replaced prematurely due to willful damage of the fixture and/or when minor repairs can be performed and the customer choses to voluntarily upgrade to LED.

7. DEC will close HPS to new installations in all lighting class Rate Schedules (PL, GL, and OL) to lessen the impact on the net book value to all lighting. Where the governmental customer requests the continued use of the same HPS fixture type for appearance reasons, DEC will attempt to provide such fixture, and the governmental customer shall be billed in accordance with the applicable provisions on Schedule PL.

8. The Company’s floodlight service is currently billed on Schedule FL. In this Docket, DEC requested to close Schedule FL and move the floodlights to either Schedule OL (private customers) or to

Schedule GL, (public customers). Effective upon Commission approval, DEC will proceed to add the governmental floodlights to Schedule GL at the proposed rates. Effective September 1, 2018, DEC will move these newly added floodlight from Schedule GL to Schedule PL, including any notations and applicable rates at the same time that DEC transitions the other non-floodlights from Schedule GL to Schedule PL.

9. As of September 1, 2018, governmental customers seeking new non-floodlight service which involves installing a new pole and/or new underground service will pay the current new pole and underground charges on Schedule GL. Currently, a standard wood pole is $6.49 per pole and underground charges begin at $4.62 up to 150 feet. The aforementioned fees will not be applicable to fixtures, poles and underground services for non-floodlights moved from Schedule GL to Schedule PL. Current PL fees for such services will apply unless otherwise modified in a future rate proceeding.

10. When Schedule GL is merged into the new PL, the Company will continue to provide an option for customers to prepay the initial capital costs of poles and underground wiring for products with the tiered rate structure (existing pole, new pole, and new pole underground) as provided for in Paragraph 9. These products will include LEDs and floodlights that are merging from GL to PL with the tiered rate design. Thus, if customers chose to prepay capital costs for the pole and underground wiring, customers will be billed for the existing pole rates accordingly.

11. As part of DEC's proposal to accelerate the conversion of MV fixtures to LED for governmental customers, the Company agrees to file semi-annual conversion progress reports with the Commission as proposed in the Docket testimony of Public Staff witness Jack Floyd. The Company will also provide governmental customer-specific data regarding proactive MV to LED conversions to impacted governmental customers before such work begins, as well as providing information summarizing the benefits of the conversion to LED for each governmental customer.

12. The Company will continue regular meetings with the NCLM and all interested localities at mutually convenient times and locations to discuss outdoor lighting issues.

Lighting Settlement, pp. 2-5.

In light of the parties' testimony and the Lighting Settlement, which the Commission accepts in its entirety and upon which the Commission places substantial weight, the Commission finds and concludes that the Company's proposed lighting rate schedules, as modified by the Lighting Settlement, are just and reasonable.

Standby Service

Standby service is where the Company provides service to customers with customer-owned generation during times when the generation either isn't operating or fails to operate and requires additional capacity and energy to be provided by the Company. Several of the Company's tariffs have some form of standby service. Based on witness Pirro's testimony, the Company developed, since the last rate case, an approach to pricing service to net metering customers with solar generation that was ultimately approved in South Carolina as the result of a collaborative agreement.

Further, witness Pirro testified that the Company has closely monitored developments leading up to House Bill 589 and its subsequent passage into law. There are multiple requirements for the Company to comply with this legislation, including changes to the current net metering tariffs. Witness Pirro noted that the Company's analysis in South Carolina will be useful for this purpose. The Company intends to pursue these changes outside of this general rate proceeding and believes that standby service consideration will be a critical part of that discussion. For the interim, witness Pirro testified that standby service is priced in the same manner as that supported by the Company and approved by the Commission in the last rate case.

Public Staff witness Floyd testified that "[g]iven the Company's proposed continuation of the current structure for standby charges until the net metering proceeding, and the small increase proposed for the rate itself, I consider the Company's proposal to be reasonable at this time." Tr. Vol. 23, p. 65.

The Commercial Group in its post-hearing Brief stated that:

> The Commercial Group opposes the structure of DEC's current and proposed standby service. Tr. Vol. 26, p. 529. However, recent N.C. legislation (Session Law 2017-192) would require DEC and other electric utilities to file new net metering rates that are set such that customer-generators pay their full fixed cost of service (but not more than their cost of service). Accordingly, the Commercial Group is deferring its advocacy on those issues to any upcoming proceedings regarding House Bill 589 compliance.

Id.

The Commission concurs with the Company's position and will address standby charges in an upcoming docket.

Summary with Respect to Rate Design

Based on the testimony of Company witnesses Pirro and Cowling, with consideration of the testimony of witnesses Floyd, Coughlan, Fisher, Hunnicutt, Watkins, Alvarez, and Phillips, as well as the Stipulation and the Lighting Settlement, the Commission finds and concludes that the rate design provisions in Section IV.E of the

Stipulation as well as the Lighting Settlement are just and reasonable to all parties in light of all the evidence presented.

The Stipulation states that "[t]o the extent possible, the Company shall assign the approved revenue requirement consistent with the principles regarding revenue apportionment described in the testimony of Public Staff witness Floyd." See § IV.E.1 of Stipulation. Specifically, witness Floyd's testimony stated:

> That any proposed revenue change be apportioned to the customer classes, especially for the lighting class, such that: (a) Class RORs are within a band of reasonableness of ± 10% relative to the overall NC retail ROR; (b) All class RORs move closer to parity with the NC retail ROR; (c) The revenue increase to any one customer class is limited to no more than two percentage points greater than the NC retail jurisdictional percentage increase, with priority given to the percentage increase versus the ROR band of reasonableness; and (d) Subsidization among the customer classes is minimized.

Id.

The Commercial Group presented the testimony of witnesses Chriss and Rosa including a recommendation that "[i]f the Commission determines that the appropriate revenue requirement is less than that proposed by the Company, the Commission should use the reduction in revenue requirement to move each customer class closer to its respective cost of service while ensuring that all classes see a reduction from DEC's initially proposed increases." The Commission concludes that it is reasonable, to the extent possible, for the Company to consider the Commercial Group's recommendation when assigning approved revenue requirements.

Further, the Commission approves DEC's proposal to discontinue the Residential Water Heating Service Controlled/Sub Metered Schedule. The Commission is, however, concerned that discontinuing programs that can be used to effectively clip winter peaks is moving in the wrong direction. This is especially true given the fact that the Company has moved to "winter planning." The Commission noted in its Order accepting 2017 IRP update reports that "DEC's 2017 IRP includes winter DSM resources that are approximately 80 MW less than included in its 2016 IRP Report." See Order Accepting Filing of 2017 Update Reports and Accepting 2017 REPS Compliance Plans, Docket E-100, Sub 147, p. 7. The Commission concludes that additional emphasis on winter DSM resource planning is warranted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 31-33

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1, and the testimony and exhibits of DEC witnesses Fountain, Simpson, Pirro and McManeus, and Public Staff witnesses Williamson and Boswell and the entire record in this proceeding.

Vegetation Management

Company witness Simpson testified that vegetation management is a critical component of the Company's power delivery operation. Tr. Vol. 16, p. 100. He explained that DEC uses a reliability-based prioritization model to drive its routine integrated vegetation management program. Id. According to witness Simpson, in addition to routine circuit maintenance, there are four other important components to the Company's overall vegetation management approach:

(1) Herbicide spraying of the "floor" of the right-of-way is planned on a periodic basis to control the re-growth of incompatible vegetation in non-landscaped areas and where property owners allow the Company to spray;
(2) Cutting down of "hazard trees" outside of the area normally maintained on a distribution line. The Company implemented this program in 2014 and has been successful in targeting removal of diseased, decayed, or dying trees to preserve the integrity and safety of DEC's lines;
(3) Unplanned work performed at the direction of reliability engineering as a result of outage follow-up investigations or by customer-initiated requests; and
(4) Disciplined vegetation management outage follow-up process tied to a formal internal reliability review process.

Id. at 100-01.

In addition, witness Simpson described how as a result of the Company's worsening trends in SAIDI and SAIFI[24] and the Company's commitment to continue to improve reliability, DEC is enhancing its vegetation management program through a focus on the following areas, all of which require additional funding:

- An increase in the frequency of trimming to stabilize and improve the vegetation management impact on overall reliability performance;
- Increase frequency of herbicide application where appropriate;
- Evaluate the feasibility of a Tree Growth Regulator program; and
- Continuing other aspects of the current program, such as distribution line "hazard tree" cutting and a disciplined vegetation management outage follow-up process.

Id. at 102-03. As explained by DEC witness McManeus, the Company has included a pro forma adjustment related to an expected $15.8 million increase in system expenditures,

[24] SAIDI and SAIFI are metrics that reflect the averages duration and frequency of power outages.

or $11.3 million on a North Carolina retail basis,[25] to reflect these enhancements to the Company's vegetation management program. Tr. Vol. 6, p. 264. Witness Simpson testified that this increase in funding will strengthen DEC's vegetation management plan and help maximize the effectiveness of the Company's planned grid improvements. Tr. Vol. 16, p. 103. He added that the Company believes that the additional funding and implementation of its plan, with these enhancements, will benefit customers. Id.

Public Staff witness Williamson testified that the Company initiated its current vegetation work cycle, referred to as the "5/7/9 plan" in 2013. Tr. Vol. 22, p. 43. He explained that the plan represented a change from a reliability-based approach to vegetation management to a cyclical approach. Id. The plan classifies DEC's distribution circuit-miles into three categories, maintained on three independent cycle periods: "Old-urban" – five years; "Mountain" – seven years; and "Other" – nine years. Id. He noted that these cycles were determined from a vegetation growth study conducted by DEC's consultant. Id. He stated that during the first five years of the plan, the Company completed vegetation management on 88% of the target miles. Id. at 44. For this period, he opined that the Company is behind their combined target miles for all categories, thus creating a back-log of approximately 3,752 miles. Id.

Additionally, witness Williamson indicated that when DEC initiated the 5/7/9 plan in 2013, the Company had developed a back-log of approximately 11,000 miles, and that as of January 2018 the current balance of those back-log miles was approximately 10,000 miles. Id. at 45. He contended that the Company would not need to address the 10,000 mile back-log if a proper, cyclical vegetation management program had been in use by the Company prior to 2013. Id. at 46. As a result, Public Staff witness Boswell recommended a pro forma adjustment to vegetation management test year expenses. Tr. Vol. 26, p. 596. The Public Staff's adjustment maintains the reactive, herbicide, and contract inspector program costs at test year actual spending levels, but applies a 7% increase in contractor vegetation management production labor costs. Tr. Vol. 22, p. 45.

Witness Simpson described how the Company performed a vegetation growth study to determine the optimum level of vegetation management for DEC's system, and that the Company used the results of that study to develop the 5/7/9 plan. Tr. Vol. 23, pp. 155-56. According to witness Simpson, the Company's last rate case did not fully fund the plan. Id. at 156. As a result, even though the Company has been spending above the vegetation management amounts included in rates from the last rate case, the Company has only been able to complete vegetation management on 88% of the planned miles during the five years since the 5/7/9 plan was adopted. Id.

Witness Simpson further stated that the Public Staff's recommended adjustment only took into account a 7% increase in contract rates for 2017 and did not consider that the 5/7/9 plan is still not funded. Id. at 156-57. In addition, he mentioned that the Public Staff did not acknowledge the Company's requested increase for transmission vegetation

[25] In her December 18, 2017 revised supplemental direct testimony and exhibits, witness McManeus adjusted these amounts to reflect increased labor costs due to higher contractor rates. Tr. Vol. 6, p. 290.

management. Id. at 158. He also noted that the Public Staff gave no consideration for the 2018 contractor rate increases, given that executed contracts could not be provided until after they were signed on January 24, 2018. Id. at 157. In her second supplemental testimony and exhibits, as well as her rebuttal testimony and exhibits, witness McManeus revised her adjustment to vegetation management expenses to reflect higher contractor rates in recently executed contracts. Tr. Vol. 6, pp. 298, 343. Those contracts resulted in an increase in 2018 rates of 18%. Tr. Vol. 23, p. 157. The revised rates resulted in an increase in production costs of $55.8 million versus the $44.9 million calculated in witness Boswell's schedule. Id. The new contracts also include increases for the demand costs, which are now $2.9 million versus the $2.4 million calculated by witness Boswell. Id. Witness Simpson noted that confirmation of the contractor increases was not available until after Public Staff filed its testimony, and that this is a key piece of information that the Commission should take note of and that may influence Public Staff's view. Id. at 155.

Witness Simpson concluded that given prudent increases in spending, known and measurable increases in contractor rates, and the commitment of the Company to its vegetation management cycles, it is reasonable for the Commission to approve its request to increase funding for vegetation management. Id.

The Stipulation provides that the Company should be allowed to recover distribution vegetation management costs in an annual amount of $62.6 million on a total system basis. Stipulation, Section III.A. For the purpose of complying with the Company's current vegetation management program, the Company committed to eliminate completely the 13,467 miles of Existing Backlog as of December 31, 2017 within five years after the date rates go into effect in this proceeding, and the Company additionally committed to spending the necessary amount on an annual basis to trim its annual target distribution miles under its 5/7/9 Plan. In addition, DEC agreed to provide a report annually to the Commission with the following information: (1) actual 5/7/9 and Existing Backlog miles maintained in the previous calendar year; (2) current level of Existing Backlog miles; (3) vegetation management maintenance dollars budgeted for the previous calendar year for 5/7/9 and Existing Backlog; and (4) vegetation management maintenance dollars expended in the previous calendar year for 5/7/9 and Existing Backlog. The Company further agreed that any accelerated amount of expenditures to eliminate the Existing Backlog miles shall not be used to increase the level of vegetation management expenses in future proceedings, but shall not prohibit the Company from seeking adjustments for vegetation management contractor rate increases. The Commission finds that this provision of the Stipulation represents a reasonable compromise of this disputed issue. The Commission, therefore, finds and concludes that DEC's and the Public Staff's agreement relating to vegetation management, as set forth in Section III.A of the Stipulation, is just and reasonable to all parties in light of all the evidence presented.

Quality of Service

Witness Fountain provided testimony relating to the Company's service quality and ways in which the Company is working to enhance the customer experience. Tr. Vol. 6,

p. 186. Witness Fountain noted that customer satisfaction (CSAT) is a key focus area for DEC. Id. The Company's CSAT program includes both national benchmarking studies and proprietary transaction and relationship CSAT studies. Id. Witness Fountain explained that the Company leverages results from these studies to drive improvement to processes, technology, and behavior, in order to improve CSAT. Id. He indicated that DEC's J.D. Power's Electric Utility Residential Study scores are trending up, with the Company being among the most improved in the 2017 study, and closing the gap toward top quartile performance. Id.

Witness Fountain testified that DEC measures overall customer satisfaction and perceptions about the Company via its proprietary relationship study, the "Customer Perceptions Tracker." Id. Random surveys are taken from residential and small/medium business customers, and all large business electric customers, to better understand their customer experience with Duke Energy and overall perceptions of the Company. Id. He stated that Duke Energy North Carolina Residential satisfaction scores are up over ten points on average from 2013, with recent trends even higher. Id. at 187.

As explained by witness Fountain, in addition to its relationship study, DEC utilizes Fastrack, the Company's proprietary transaction study, to measure overall customer satisfaction with the Company's operational performance (i.e., responding to and resolving customer service requests). Id. Each year, thousands of interviews are conducted with DEC customers by a third-party research supplier upon the completion of the customers' service request. Id. The survey questions cover the entire experience, from the time the customer picks up the phone to contact the Company, until the issue is resolved. Id. Witness Fountain indicated that analysis of these ratings helps to identify specific service strengths and opportunities that drive overall satisfaction and to provide guidance for the implementation of process and performance improvement efforts. Id. Through mid-2017, roughly 85% of DEC's residential customers expressed high levels of satisfaction with these key service interactions (Start/Transfer Service, Outage/Restoration, Street Light Repair, etc.). Id.

Witness Fountain testified that in 2016, Customer Satisfaction continued as one of a select number of goals included in the annual incentive compensation plans for DEC employees. Id. According to witness Fountain, by connecting customer satisfaction directly to compensation, each employee is invested in improving and maintaining high customer satisfaction for all Duke Energy utilities, including DEC. Id. at 187-88. Results are monitored at the enterprise level, state level, and by customer segment, so problems can be identified and corrected. Id. at 188. This also allows the Company to identify and apply best practices across all Duke Energy jurisdictions. Id.

Finally, witness Fountain stated that the Company continues to enhance its customer service practices to address language, cultural, and disability barriers. Id. Among other accommodations, the Company's customer service center offers customer service and correspondence in Spanish, handles calls from TTY devices (text telephones), offers bills in Braille, and accepts pledges to pay from social service agencies. Id.

Public Staff witness Williamson also provided testimony regarding DEC's quality of service. Tr. Vol. 22, pp. 47-48. In evaluating the Company's overall quality of service, he reviewed the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) data filed by the Company in Docket No. E-100, Sub 138A; informal complaints and inquiries from DEC's customers received by the Public Staff's Consumer Services Division; filed Statements of Position in this docket; and his own interactions with DEC and its customers. Id. at 47. He noted that for the period 2008 through 2016, Company reports showed the SAIDI and SAIFI indices are worsening. Id. These trends show that the Company's outages are increasing in frequency, and when outages occur they tend to have a longer duration, on average. Id. He also stated that less than 1% of the direct contacts that the Public Staff's Consumer Service Division received from DEC customers related to service quality issues. Id. at 48. Witness Williamson concluded that the quality of service provided by DEC to its North Carolina retail customers is adequate at this time. Id.

No intervenor offered evidence contradicting the testimony and agreement of the Stipulating Parties that the quality of DEC's service is adequate. Therefore, consistent with the evidence and Section IV.J. of the Stipulation, the Commission finds and concludes that the overall quality of electric service provided by DEC is adequate.

Service Regulations

Witness Pirro described the proposed changes to DEC's Service Regulations. His pre-filed direct testimony on this matter was modified by his updated Exhibit 1 filed on December 19, 2017. Most of the revisions involve relatively small changes in charges, increases in some and decreases in others, imposed by DEC for various services, including the following.

(1) An increase in the reconnection fee from $25.00 to $27.13 during regular business hours, and a decrease from $75.00 to $27.13 during all other hours [Section XII].

(2) An increase in the initial customer connection charge from $15.00 to $24.18. [Section II].

(3) A decrease in the returned check charge from $20.00 to $5.00 [Section XII].

(4) A decrease in the monthly charge for extra facilities over and above those normally provided from 1.1% of the estimated cost to 1.0% per month, but not less than $25 [Section XVI(16)].

In addition, pursuant to DEC's present Service Regulations, if a residential dwelling unit does not meet the definition of "permanent," it will be considered temporary and service will be provided under a general service rate schedule. DEC proposed the following underlined language to Section XVI(1) and (2).

> [A]dditonally, for a manufactured home to be considered permanent, it must also be attached to a permanent foundation, connected to permanent water and sewer facilities, labeled as a structure which can be used as a permanent dwelling, and under a lease arrangement for five (5) years or longer or located on customer-owned land. If the structure does not meet the requirements of a permanent dwelling unit, service will be considered temporary and provided on one of the general service rate schedules.
>
> [M]anufactured homes which meet the requirements of a permanent residence under XVI above will be billed in accordance with the applicable residential rate schedule. Nonpermanent manufactured homes will be provided service under XVI(15) Temporary Service below and billed in accordance with the applicable general service rate schedule.

The Commission notes that one of the consequences of Temporary Service is that the customer must pay DEC's actual cost of connection and disconnection, which may be higher than the charges noted above.

Under Section V of its Service Regulations, with regard to rights-of-way, DEC initially proposed the addition of the following underlined language in the first paragraph:

> The Customer shall at all times furnish the Company a satisfactory and lawful right of way easement over his premises for the construction, maintenance and operation of the Company's lines and apparatus necessary or incidental to the furnishing of service. In the absence of formal conveyance, the Company, nevertheless, shall be vested with an easement over Customer's premises authorizing it to do all things necessary to the construction, maintenance and operation of its lines and apparatus for such purpose.

On April 27, 2018, DEC filed a letter stating that it had decided to withdraw from consideration the second sentence proposed under Section V. The Commission accepts DEC's withdrawal of that proposed additional sentence.

No party filed testimony regarding DEC's proposed changes to its Service Regulations. The Commission finds and concludes that DEC's proposed amendments to its Service Regulations are just and reasonable, serve the public interest, and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 34-35

The evidence supporting these findings of fact and conclusions is contained in the Company's Application and Form E-1, the testimony and exhibits of the DEC and Public Staff witnesses, the Stipulation and the Lighting Settlement, and the entire record in this proceeding.

As fully discussed above, the provisions of the Stipulation are the product of the give-and-take of settlement negotiations between DEC and the Public Staff. Comparing the Stipulation to DEC's Application, and considering the direct testimony of the Public Staff's witnesses, the Commission notes that the Stipulation results in a number of downward adjustments to the costs sought to be recovered by DEC. Further, the Commission observes that there are provisions of the Stipulation that are more important to DEC, and, likewise, there are provisions that are more important to the Public Staff. For example, the Public Staff was intent on obtaining a commitment from the Company regarding vegetation management and reduction of the Company's untrimmed, back-log miles. Likewise, DEC was intent on holding the record of this proceeding open to allow the Company to include the final cost amounts of the Lee CC project. Nonetheless, working from different starting points and different perspectives, the Stipulating Parties were able to find common ground and achieve a balanced settlement.

The result is that the Stipulation strikes a fair balance between the interests of DEC and its customers. As discussed above, the Commission has fully evaluated the provisions of the Stipulation and concludes, in the exercise of its independent judgment, that the provisions of the Stipulation are just and reasonable to all parties to this proceeding in light of the evidence presented, and serve the public interest. The provisions of the Stipulation strike the appropriate balance between the interests of DEC's customers in receiving safe, adequate, and reliable electric service at the lowest reasonably possible rates, and the interests of DEC in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. Further, the Commission finds and concludes that the revenue requirement, rate design, and the rates that will result from the Stipulation, subject to the Commission's decisions set forth below on the contested issues, will provide just and reasonable rates for DEC and its retail customers.

Therefore, the Commission approves the Stipulation in its entirety. In addition, the Commission finds and concludes that the Stipulation is entitled to substantial weight and consideration in the Commission's decision in this docket. Further, the Commission concludes that the Lighting Settlement entered into by DEC with NCLM, and the Cities of Concord, Kings Mountain, and Durham is in the public interest and should be approved in its entirety.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 36

The evidence supporting this finding and conclusions is contained in the verified Application and Form E-1 of DEC, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Company witness Pirro explained that the Company proposes to increase (or decrease) the BFC for each rate class to better reflect the underlying cost of serving customers regardless of the customer's level of energy use. Tr. Vol. 19, pp. 60, 63. Pirro Exhibit 8 shows the Company's proposed BFCs, which are based on a percentage difference between the current BFC and the costs determined in the Company's cost of service study provided by witness McManeus. Id. at 63. Specifically, DEC proposes to increase the monthly BFC for the residential rate class, other than Schedule RT, from $11.80 to $17.79, which reflects approximately 50% of the difference between the current rate of $11.80 and the customer-related cost of $23.78 identified in the cost study. Id. at 60; Pirro Ex. 8. Although the Company's analysis supports increasing the residential BFC to $23.78, the Company has proposed a smaller increase to moderate any effect on low-usage customers. Id.

Several intervenors provided testimony regarding the Company's proposed increases to the BFCs. Public Staff witness Floyd testified that DEC's requested increase is unreasonable given the impact of a large increase on low-usage customers. Tr. Vol. 23, p. 63. He notes that the BFC is an unavoidable charge and constitutes a large percentage of the bill for low-usage residential customers. Id. Witness Floyd explained that if DEC is granted its requested rate increase, approximately 45% of the total revenue increase from residential customers will come solely from the increase in the BFC. Id.

Witness Floyd recommends that any increase in the residential BFC should be limited to 25% of the approved revenue increase assigned to that customer class. Tr. Vol. 23, p. 64. Under the Company's proposed revenue increase of approximately $612 million, this produces a BFC of approximately $15.10 for Schedule RS. Id. at 63-64. Alternatively, witness Floyd recommended that the BFC remain unchanged in the event the Commission ordered a decrease in the revenue requirement as a result of this proceeding. Id. at 64.

NCSEA witness Barnes testified that the Company's proposed fixed customer charge increases are "extreme" and recommended that the current customer charges be maintained, or, alternatively, that the customer charges only be increased by the percentage increase in the overall revenue requirements adopted for each class. Tr. Vol. 20, p. 61. Specifically, witness Barnes testified that the increased residential BFC proposed by the Company was higher than other utilities and is therefore inappropriate. Id. at 66-69. Witness Barnes also argues that the proposed increases are inconsistent with the ratemaking principle of gradualism. Id. at 70.

Witness Barnes, as well as NC Justice Center, et al. witness Wallach, also assert that an increase in the customer charge dilutes customer incentives for distributed generation and energy efficiency. See id. at 71-73; Tr. Vol. 8, pp. 70-76. Witness Wallach argues that the customer charge should be consistent with the "true minimum plant cost per customer" (which is $11.08/month for residential customers), and that all other customer-related costs should be included in the volumetric energy rate. Tr. Vol. 8, pp. 68-72. Witness Wallach also takes issue with the Company's use of the minimum system analysis to determine customer-related distribution plant costs, as further discussed in this Order in the analysis related to Finding and Conclusion No. 28. Id. at 66-67. Witness Wallach argues that the fact that the BFC "exceeds the true customer-related embedded cost per residential customer indicates that a portion of demand-related distribution plant costs are inappropriately being recovered through the current BFC." Id. at 68. Therefore, residential customers with low usage are subsidizing larger customers under DEC's proposed rates. Id.

NC Justice Center, et al. witness Deberry also opposed the increased residential BFC, testifying that it will affect already cost-burdened residents who struggle to afford housing costs. Tr. Vol. 26, p. 348. Witness Deberry explained that over half of all cost-burdened households are renters without the ability to make investments in energy efficiency. Id. at 350-52. She further explained that the increased BFC would reduce incentives from bill savings for landlords to include utility programs in their property management, and thus the costs of an increased BFC would be passed on to customers least able to afford it. Id. at 354.

Similarly, NC Justice Center, et al. witness Howat testified that increasing fixed customer charges disproportionately impacts low-volume, low-income customers and discourages energy efficiency. Tr. Vol. 8, p. 22. Witness Howat testified that low-income households, and particularly low-income households of color, are at a heightened risk of loss of home energy service. Id. at 31-34.

In addition to the expert testimony of witnesses Howat and Deberry, other non-expert witnesses speaking at the public hearings testified about the hardship of increases in fixed charges to low-income households and senior citizens.

NC Justice Center, et al. in its post-hearing Brief stated that:

> It is in large part because of this disproportionate harm to those subsisting on low and fixed incomes that the National Association of State Utility Customer Advocates (NASUCA) is opposed to increases in mandatory, fixed charges like the BFC in this case. NASUCA Resolution 2015-1 (NCJC et al. Floyd Cross Exhibit 1, Ex. Vol. 23, p. 104.) The NASUCA resolution states that imposing a "high customer charge . . . unjustly shifts costs and disproportionately harms low-income, elderly, and minority ratepayers, in addition to low-users of gas and electric utility service in general."

Id.

The AGO stated in its brief that:

> Duke's proposal to increase the basic monthly charge for residential customers by 51% from $11.80/month to $17.79/month is extreme and inappropriate, particularly in the circumstances of this case. The proposal should be denied because it will discourage consumers from making investments in energy efficient products and home improvements or from taking other careful measures to budget their consumption, contrary to statutory public policy goals favoring energy efficiency and energy conservation.

AGO's Brief, pp. 91-92.

In his rebuttal testimony, Company witness Pirro responded to the arguments raised by these intervenors regarding the proposed increases to the residential BFC. First, he explained that "[i]t is important that the Company's rates reflect cost causation to minimize subsidization of customers within the rate class." Tr. Vol. 19, p. 83. Witness Pirro explained that "customer-related costs are unaffected by changes in customer consumption and therefore should be paid by each participant, regardless of their consumption." Id. He further explained that any customer-related revenue not recovered in the BFC is shifted to energy rates, which contrary to NC Justice Center, et al.'s position, actually results in high usage customers subsidizing the rates of lower usage customers. Id.

Witness Pirro disagreed with Public Staff witness Floyd's recommendation to limit the BFC to recover no more than 25% of the revenue increase approved for the rate class. Id. at 84. He explained that the Company shares witness Floyd's concern regarding the size of the increase and is sensitive to the impact of the BFC on its customers. Id. The Company has reflected that concern in its request to limit the increase to less than the fully justified customer-related cost. Id. An economically efficient rate design minimizes subsidization between customers and customer classes, and the Company has reflected this principle in its proposal. Id. While witness Floyd's recommendation moves to reduce subsidization, the Company is concerned that deferring a larger increase at this time merely shifts the need to increase the BFC to a future rate case proceeding. Id.

Additionally, witness Pirro responded to NCSEA witness Barnes' argument that DEC's BFC is higher than other utilities and is, therefore, inappropriate. Id. He explained that a utility's rates should be set based upon a careful examination of the individual utility's cost of service and an allocation of those costs to the jurisdictions and customer classes based upon methodologies found appropriate by the Commission. Id. In this proceeding, the Company has examined its costs and identified customer-related costs in excess of its current BFC. Id. Other utilities' cost and rates are irrelevant to a determination of DEC's rates. Id.

In response to witnesses Barnes and Wallach's assertion that an increased BFC discourages energy efficiency, Company witness Pirro countered that failing to properly recover customer-related cost via a fixed monthly charge provides an inappropriate price signal to customers and fails to adequately reflect cost causation. Id. at 85. Shifting customer-related cost to the kWh energy rate further exacerbates this concern and over-compensates energy efficiency and distributed generation for the cost avoided by their actions. Id.

Witness Pirro also responded to NC Justice Center, et al. witnesses Howat and Deberry's testimony regarding the disproportionate impact of an increased BFC on low-income customers. Witness Pirro explained that the Company is mindful of the impact of any rate increase on its customers, particularly low-income customers; however, the Company does not design rates based upon customer incomes, but rather applies cost causation principles to the extent practicable. Id. at 85. Witness Pirro explained that the Company uses other means to address the financial needs of low-income customers which are more effective than biasing the rate design, such as the Company's Residential Income Qualified Energy Efficiency and Weatherization Assistance Program, budget billing and payment arrangements, and Energy Neighbor Fund. Id. at 85-86.

At the hearing, Witness Pirro testified on redirect that the BFC increase the Company has requested is $5.99 per month, which would equate to 19 to 20 cents per day. Tr. Vol. 20, pp. 21-22. He also testified on redirect that, unfortunately, even though some of DEC's customers cannot afford such an increase, it is still appropriate to increase the BFC based upon cost causation rate design principles. Id. at 22-23. Witness Pirro explained that the Company used the concept of gradualism to effectively recover costs as they are incurred, but determined it was appropriate to seek only half of the difference between the current BFC charge and the fully-allocated cost of the BFC in this proceeding. Id. Witness Pirro further explained that any costs not recovered through the BFC are then recovered for the residential class through the energy charge, which creates different subsidies within that class. Id. at 23.

Based upon the entire record in this proceeding, the Commission concludes that DEC shall increase the monthly BFC for the residential rate class (Schedules RS, RT, RE, ES, and ESA) to $14.00. The Commission finds and concludes that the increase in the BFC for the residential rate class schedules is just and reasonable and strikes the appropriate balance providing rates that more clearly reflect actual cost causation. The increase in these schedules minimizes subsidization and provides more appropriate price signals to customers in the rate class, while also moderating the impact of such increase on low-income customers to the extent that they are high-usage customers such as those residing in poorly insulated manufactured homes. In arriving at this decision, the Commission gives substantial weight to the testimony of Company witness Pirro concerning cost of service. The Commission agrees with witness Pirro's testimony that failing to properly recover customer-related cost via a fixed monthly charge provides an inappropriate price signal to customers and fails to adequately reflect cost causation.

Further, the Commission agrees with witness Pirro's testimony that shifting customer-related cost to the kWh energy rate further exacerbates these concerns and may over-compensate energy efficiency and distributed generation for the cost avoided by their actions. However, the Commission does not find sufficient support in this proceeding to increase the BFC to $17.79 as proposed by the Company. Rather, the Commission in this proceeding finds, in response to parties resisting any increase in the BFC, that the modified increase in the residential BFC is appropriate. The Commission finds and concludes that it is just and reasonable that the BFC for other non-residential rate schedules shall be left unchanged at this time based upon the evidence in the record. In support of these conclusions, the Commission notes that other non-residential rate schedules are more complex, thus allowing for the minimization of cost-subsidization issues and ensuring greater consistency with cost causation and allocation principles. In addition, the Commission notes that a greater amount of fixed costs in the residential rate schedule, as opposed to non-residential rate schedules, presently are recovered through variable energy rates, which is inconsistent with basic cost allocation principles that fixed costs should be recovered through fixed charges, whereas variable costs should be recovered through variable charges. The Commission further notes that it likely will review and evaluate several competing theories on this issue in the near future, when a docket is created to review net metering rate schedules pursuant to the directive set forth in House Bill 589. Finally, although the parties dispute the extent to which the residential class should bear responsibility for fixed or demand related costs, the $14.00 charge the Commission approves lies within the range of the charges advocated by the parties. In its discretion, the Commission determines that $14.00 is the appropriate charge for purposes of this case. While DEC's evidence would support a higher charge, the Commission determines that cost causation analyses are inherently subjective and selecting a charge within the range advocated based on differing cost causation models is appropriate.

The Commission is sensitive to the impact of increasing fixed costs to any customer and especially low-income households. Nevertheless, all customer classes and the residential class in particular are composed of individual consumers with divergent usage patterns and financial situations. Class rates by definition are based on averages. Any changes in rate structure affects individual consumers differently depending on their usage. The Commission acknowledges the testimony of witness Pirro where he explained that the Company uses other means to address the financial needs of low-income customers which are more effective than biasing the rate design. In its cover letter, dated June 1, 2018, concerning the Pilot Grid Rider Agreement, the Company committed to making a shareholder-funded contribution totaling $4 million to certain programs to help mitigate the impact of rate adjustments on low-income customers and to support job training. The Commission fully endorses the Company's desire to contribute shareholder funds to support low-income programs and concludes that the $4 million should be used exclusively for the benefit of low-income customers through programs such as Share the Warmth. The Commission encourages the Company, to the extent it is able, to identify low-income customers likely to discontinue service prior to bringing their accounts up to date, in order to provide assistance and thereby reducing uncollectible accounts.

<u>EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 37</u>

The evidence supporting this finding of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

The Stipulating Parties have not agreed regarding the methodology for calculating customer usage through December 2017. While Public Staff witness Saillor generally adopted the Company's approach, he made certain modifications to the Company's calculations. Tr. Vol. 19, pp. 98-99. The Company agrees with some of the modifications proposed by witness Saillor,[26] however, there are a few changes to witness Saillor's

[26] For instance, witness Saillor proposed the use of weather-adjusted data instead of the actual billed usage which the Company does not oppose. Tr. Vol. 19, p. 99.

proposal that the Company proposes in order to "place the growth adjustment on a sound footing and to provide a consistent methodology." Id. at 99. In his rebuttal testimony, witness Pirro explained that the Company proposes (a) to remove the usage adjustment made for the test period, (b) to eliminate the use of a de-trending scheme used in the usage adjustment for the extended period, and (c) to include the lost sales of closed accounts in the extended period. Id.

First, witness Saillor made a usage adjustment of 29,329,823 kWh, which was calculated as an adjustment of the test period Y2016 to the previous year Y2015. Id.; Tr. Vol. 26, p. 904. Witness Pirro explained that while there is a basis for adjusting the usage in the test period (Y2016) for the usage in the extended period (Y2017) because the Company included the extended period in its calculations, there is no basis for including the previous year (Y2015). Tr. Vol. 19, pp. 99-100. He explained that Y2015 is not within scope of this proceeding and requires no linkages with test period data for the purpose of a usage adjustment. Id. at 100.

Secondly, witness Pirro explained that the Company does not agree with witness Saillor's usage adjustment of 314,916,793 kWh for residential accounts that employs a de-trending scheme. Id. Witness Pirro asserted that this adjustment is arbitrary and unnecessary. Id. He explained that the regression models used to predict customers at end of period have in effect already de-trended the per capita usage. Id. Also, witness Saillor's method uses an averaging scheme that uses data points twelve months apart and therefore the sales for which the adjustments are being calculated are not the total sales for the period. Id. Witness Pirro explained that the Company has recomputed the usage adjustment using the same weather adjusted series that Saillor has used but without the de-trending. Id.

Additionally, witness Saillor extended the customer growth adjustment from the end of the test period to November 30, 2017, to correspond with the Company's decision to update for plant additions and related expenses through that date. Tr. Vol. 26, p. 904. Witness Pirro explained that for the lost sales from initial accounts, witness Saillor adds 12 months of estimated sales to the new customers during the extended period (through November 2017) to the initial estimate. Tr. Vol. 19, p. 100. However, the closed accounts have only their test period sales removed which differs from the treatment of initial accounts. Id. For parity, witness Pirro asserted that the entire usage of the closed accounts from January 2016 through November 2017 should be used, and the Company has added the usage of closed accounts in the extended period to the customer-by-customer adjustment. Id.

Finally, witness Pirro testified that the 12 months ended December 2017, which includes an additional month to the original analysis which was terminated at November 2017, should be used. Id. at 101. He explained that such an analysis was provided to the Public Staff but it did not include the modifications proposed by witness Saillor. Id. The Company therefore submitted an updated analysis for the 12 months ended December 2017 accepting the use of weather-adjusted usage data but rejecting the items described above and recommended that it be adopted in this proceeding and used to determine the growth adjustment. Id. In his supplemental testimony, witness Saillor incorporated customer data for the month of December 2017 in his customer growth analysis. Tr. Vol. 26, p. 911.

In light of the evidence presented, the Commission finds and concludes that Public Staff witness Saillor's methodology for calculating customer usage as set forth in his testimony, with the adjustments proposed by Company witness Pirro in his rebuttal testimony, is just and reasonable to all of the parties and should be employed by the Company in this case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 38-40

The evidence supporting these findings of fact and conclusions is contained in the Company's verified Application, Form E-1, the record in Docket No. E-100, Sub 147 from October 3, 2016, and the testimony and exhibits of the following expert witnesses: DEC witnesses Schneider, McManeus and Pirro; Public Staff witnesses Floyd, McCullar and Maness; EDF witness Alvarez; and NCSEA witness Murray.

Proceedings in Docket No. E-100, Sub 147

By Orders dated April 11, 2012, and May 6, 2013, in Docket No. E-100, Sub 126, the Commission adopted rules requiring electric utilities, that file integrated resource plans (IRPs), to include in their IRPs information on how planned "smart grid" deployment would impact the utilities' resource needs. In addition, the Commission established a new requirement, Rule R8-60.1, for the electric utilities to file smart grid technology plans (SGTPs) every two years, with updates in the intervening years. The initial SGTPs were filed by the electric utilities on October 1, 2014.

On October 3, 2016, DEC and Duke Energy Progress, LLC (DEP) filed their SGTPs in Docket No. E-100, Sub 147 (SGTP Docket). Dominion Energy North Carolina (DENC) had previously filed its SGTP. Subsequently, comments were filed by the Public Staff, NCSEA and EDF. In addition, reply comments were filed by DENC, and jointly by DEP and DEC.

In summary, DEC's 2016 SGTP identified 14 smart grid technology projects that it was in the process of implementing, or was planning to implement in the next five years. Two such projects are AMI Phase 2 and AMI Expansion 2015. With regard to AMI Phase 2, DEC explained that it initiated a limited-scale project in 2013 leveraging grant funds from the U.S. Department of Energy (DOE) to deploy AMI in North Carolina and South Carolina. Phase 2 of the project replaced aging Advanced Meter Reading (AMR) meters with AMI. Phase 2 was completed in the first quarter of 2015. Including the meters previously installed in Phase 1, the project has installed about 313,500 AMI meters in North Carolina.

With respect to AMI Expansion 2015, DEC stated that it pursued a limited-scope AMI project to install approximately 181,000 AMI meters to serve residential customers in the Charlotte Metro area, and that the project was completed in July 2016.

DEC further stated that as of September 2016, it had cumulatively installed 527,391 AMI meters, an increase of approximately 252,260 AMI meters since its 2014 SGTP. DEC also identified four smart grid technologies actively under consideration: (1) AMI deployment; (2) usage alerts; (3) outage notifications; and (4) Pick Your Own Due Date. With respect to AMI deployment, DEC stated that in 2016 it began evaluating the case for continuing with incremental AMI deployments at about 150,000 per year, or moving forward with a project to replace all remaining AMR meters with AMI.

On March 29, 2017, the Commission issued an Order Accepting Smart Grid Technology Plans (SGTP Order) in Docket No. E-100, Sub 147. The SGTP Order reviewed and accepted the 2016 SGTPs filed by DEC, DEP and DENC.

On May 5, 2017, DEC and DEP filed supplemental information regarding DEC's and DEP's 2016 SGTPs. In summary, DEC advised the Commission that in late 2016 it decided to begin a full scale deployment of AMI in North Carolina, that it began implementing that decision in early 2017, and that it expected to complete its AMI deployment in North Carolina in 2019. DEC attached a cost-benefit analysis and other information regarding its decision to deploy AMI. The cost-benefit analysis concluded that DEC's AMI deployment would result in net benefits having a present value of $117.1 million. Supplemental Filing, Exhibit No. 2. The largest category of benefits included in the analysis is entitled, "Non-technical line loss reduction - power theft, equipment failures and installation errors" (NLLR). It is the last column of benefits shown on Exhibit No. 2, and totals $634.8 million.

On August 21, 2017, the Commission issued an Order Requiring Smart Meter Plan Presentation by Duke Energy Carolinas, LLC (SGTP Presentation Order). The Order scheduled a presentation on AMI by DEC, and included several questions to be answered by DEC regarding its decision to deploy AMI. Subsequently, in response to question number 2 included in the Commission's SGTP Presentation Order, DEC stated that the $634.8 million of NLLR included in its cost-benefit analysis was based on a 2008 report by the Electric Power Research Institute (EPRI). The EPRI report noted that industry experts project that a reasonable percentage for non-technical losses is 2% of gross revenue. DEC stated that it used this 2% of revenue approach to calculate the NLLR in its AMI cost-benefit analysis. Further, during the SGTP presentation by DEC on October 10, 2017, witness Schneider stated that based on DEC's cost-benefit analysis the costs of the AMI deployment would outweigh the benefits until 2025.

On October 2, 2017, DEC and DEP filed their SGTP update reports (SGTP Updates) in Docket No. E-100, Sub 147. In DEC's SGTP Update, on pages 6-8, DEC provided the information regarding its AMI deployment. In summary, DEC stated that through August 2017 it had installed approximately 850,000 AMI meters in North Carolina, and planned to install an additional 1.1 million AMI meters through 2019. Further, DEC stated that it would remove and replace approximately 1.32 million AMR meters from 2017 through 2019. DEC further stated that its AMR meters had an estimated salvage value of $1.37 million, and an estimated remaining net book value of $127.66 million, as of March 31, 2017. In Exhibit A, Appendix C, DEC provided its AMI cost-benefit analysis, which was the same analysis that DEC filed as a part of its supplemental information filing on May 5, 2017.

On November 20, 2017, the Commission issued an Order Requiring Additional Information (Additional Information Order) requesting that DEC respond to several questions about its AMI deployment. In addition, the Commission requested that DEC provide a revised cost-benefit analysis that included (1) DEC's historical kilowatt-hour and lost revenue data for NLLR that DEC has experienced in North Carolina, rather than using the EPRI 2% of revenue calculation, and (2) the cost of replacing AMI meters at the end of their 15-year useful life.

On December 15, 2017, DEC filed its responses, including its revised cost-benefit analysis as Exhibit No. 2. The largest category of benefits included in the analysis continued to be "Non-technical line loss reduction - power theft, equipment failures and installation errors." However, the amount of the NLLR benefit went down from $634.8 million to $448.8 million. In addition, the revised cost-benefit analysis, which included the cost of replacing AMI meters at the end of their 15-year useful life, showed that AMI deployment would result in net costs having a present value of $49.9 million.

<u>Summary of AMI Testimony</u>

DEC witness Schneider described the Company's plan to replace its current meters with AMI meters – often referred to as "smart meters" – that have advanced features, including the capability for two-way communications, interval usage measurement, tamper detection, voltage and reactive power measurement, and net metering capability. Tr. Vol. 18, p. 322. He testified that DEC began the deployment of AMI meters in 2016, and estimates completing implementation in mid-2019. <u>Id.</u> at 323. In 2016, the Company spent $73.9 million on new AMI meters across the system in North and South Carolina. <u>Id.</u> at 326. Witness Schneider explained that the Company's AMI project is not a "simple meter change-out" and will include advanced meters, a two-way communication network, and central computer systems, and that AMI is a foundational investment for DEC that will enable additional customer choice, convenience and control. <u>Id.</u> at 322-33.

Public Staff witness Floyd criticized the Company's cost-benefit analysis, arguing that the Company's expected benefit based on AMI's ability to reduce theft and other revenue losses related to meter tampering was based on an outdated EPRI study and was likely overstated. Tr. Vol. 23, p. 87. In addition, witness Floyd questioned whether the Company will immediately maximize the benefits available to customers from AMI. <u>Id.</u> at 89. He stated, for example, that customers who receive more detailed usage data from AMI should be able to use this data to save on power bills. <u>Id.</u> According to witness Floyd, customers will not be able to do so unless the Company provides new and innovative rate designs, such as TOU rate structures and new payment options, including prepay. <u>Id.</u> at 89-90. Witness Floyd also testified regarding customers who opt-out of having an AMI meter installed. <u>Id.</u> at 90-91. DEC has filed for approval of a Rider MRM in

Docket No. E-7, Sub 1115, which would allow customers who desire to opt-out to pay a monthly fee to have a fully manual meter. Id. at 90. Witness Floyd acknowledged that if a significant number of customers opt-out of having an AMI meter, the benefits of AMI deployment will be diminished. Id. The Public Staff, therefore, supports the Company's request for Rider MRM, and encourages the Commission to approve that rider as part of this rate case. Id. at 91.

Public Staff witness Maness criticized the Company's proposed recovery of the remaining book value of replaced AMR meters over three years, the expected deployment period for the AMI program. Tr. Vol. 22, p. 103. Witness Maness testified that the meters being replaced have an average remaining useful life of 15.4 years, and that period should be used in the Company's depreciation study instead of the accelerated three-year period. Id. at 104. Public Staff witness McCullar testified that the Public Staff used the 15.4 year remaining useful life in developing the Public Staff's recommended depreciation rates. Tr. Vol. 26, p. 788. Witness McCullar also testified that DEC should use a 17-year average service life for AMI meters as opposed to the 15 years that the Company has proposed. Id. at 787.

Other than these concerns, however, the Public Staff stated that "the Company has made a reasonable assessment of the costs and benefits associated with its proposed deployment of AMI." Tr. Vol. 23, p. 92. The Public Staff does not object to the inclusion of the Company's AMI costs incurred to date and included in this case. Id. at 93.

EDF witness Alvarez also testified concerning the Company's cost-benefit analysis for AMI. Tr. Vol. 26, pp. 311-13. Witness Alvarez recommended that stakeholders be allowed the opportunity to conduct a detailed examination of the Company's cost-benefit analysis for its AMI program as part of a distinct grid modernization docket. Id. at 312.

NCSEA witness Murray also recommended that the Company implement a "bring your own device" offering that allows customers to connect Home Area Networks (HAN) directly to the Company's AMI radio to access energy usage information. Tr. Vol. 26, p. 401.

Company witness Schneider testified in response to these arguments. First, he responded to the Public Staff's criticism of the Company's cost-benefit analysis. Tr. Vol. 18, pp. 331-32. He explained that the Company based its reduction in revenue erosion from meter tampering on a 2008 EPRI study because analyzing non-technical loss is significantly complex and it would not be possible to use the actual historical kilowatt-hour and lost revenue data for energy theft that DEC has experienced. Id. at 332. In response to criticism that the Company will not maximize benefit to customers, witness Schneider explained that DEC has already implemented two new programs for DEC customers with smart meters, Pick Your Due Date and Usage Alerts. Id. at 334-35. He also explained that the Company plans to offer more innovative rate designs to complement AMI in the future, as detailed by Company witness Pirro. Witness Schneider also explained that all customers receiving smart meters under the AMI project will receive benefit from remote meter reading and mass meter interrogation capabilities, which allow the Company to quickly assess outages and restore power more efficiently. Id. at 335-37.

Witness Schneider testified that DEC agrees that customers should have the choice to opt-out of the AMI meter through a cost-based tariff. Id. at 337. The Company agrees with the Public Staff that the Commission should approve the opt-out program as filed, and respectfully requests approval by the Commission soon. Id. At the hearing in response to questioning by Commissioner Gray, witness Schneider explained that when a customer expresses concern with the new AMI meters, the Company attempts to address those concerns, and if the customer is adamant about not wanting a new meter, the customer is added to a bypass list. Tr. Vol. 18, p. 415. Currently, there are approximately 4,000 people on the bypass list, which equates to 0.3% of DEC's North Carolina customers. Id. at 415-16.

Witness Schneider also addressed witness McCullar's recommendation that a 17-year average service life for AMI meters be used as opposed to the 15 years that the Company has proposed. Tr. Vol. 18, p. 338. Witness Schneider testified that "[g]iven the pace of technology advancement, the trend across the industry is shorter depreciation schedules from a regulatory and accounting perspective, as systems such as AMI are more computer and sensor driven." Id. at 338-39. He also noted that the Commissions in Indiana, Kentucky, Ohio and Florida all utilize 15-year depreciation lives for the Duke Energy AMI meters deployed in those jurisdictions. Id. at 339.

Additionally, witness Schneider responded to witnesses Alvarez's criticism of the Company's cost-benefit analysis. He explained that "the Company's AMI cost-benefit analysis was filed in DEC's SGTP on October 2, 2017 in Docket No. E-100, Sub 147.[27] Id. at 339. "In past SGTP dockets, the Company has discussed that parties likely have different definitions of a "cost-benefit" analysis, and there is not a standard template that every project related to smart grid technologies follows in completing the evaluation and analysis for determining the business case for a specific technology." Id. Instead, many different factors go into the Company's decision to invest in a specific technology at a specific time. Id. Witness Schneider explained that "DE Carolinas believes that the Commission's existing SGTP, ratemaking, and EE/DSM processes provide opportunity for stakeholder engagement and comment in the development and approval of such programs to maximize customer benefits." Id. at 340. Moreover, witness Schneider rejected witness Alvarez's recommendation to open a new AMI docket as duplicative, stating that "[t]he Commission already has a SGTP rule and dockets to review, allow for intervenor investigation and comment, and ultimately accept, modify or reject the Company's SGTP and those of the other utilities" and that cost recovery for the AMI project will be subject to the existing robust and transparent rate case process." Id. at 342.

[27] The Commission has taken judicial notice of all filings in Docket No. E-100, Sub 147. Tr. Vol. 18, p. 402.

Finally, witness Schneider testified in opposition to witness Murray's recommendation regarding the "bring your own device" offering. Id. at 343-44. He explained that smart meter to HAN connections combine two separate security risks. Id. at 343. First, the current lack of security within internet devices, gateways and applications, and second, external connections to critical infrastructure. Id. For both topics, Duke Energy is deliberately and carefully evaluating the associated risk to the reliability of the power grid. Id. The Company is considering: (1) research conducted by third parties; (2) compliance with National Institute of Standards and Technology (NIST) based security standards that federal and state commissions have encouraged the Company to adopt; and (3) alignment with recently released security principles related to both topics provided by the Department of Homeland Security (DHS), National Security Agency (NSA) and the Department of Energy (DOE). Id. Cyber security threats are of the utmost concern to the Company and therefore, DEC does not support the "bring your own device" recommendation by witness Murray at this time. Id. Furthermore, on cross-examination by counsel for EDF at the hearing, witness Schneider supported the Company's position on HAN connections, stating that the Company's cyber security experts have "grave concern" about allowing external connections to the Company's critical grid structure. Id. at 357.

Witness Schneider explained that a secondary concern regarding the "bring your own device" offering is support and upgradeability. Id. at 343. At this time, if a customer buys a device not known to the Company, DEC would not be able to provide support to the customer if that device fails or is not able to connect to the meter. Id. at 343-44. If a new security release is made available the Company may push that to the meter. Id. at 344. The Company would be unable to ensure that a new version that was pushed to the meter is compatible with all of the devices that a customer may have purchased. Id. Customer satisfaction would be impacted along with a large increase in call volumes. Id. Therefore, witness Schneider testified that the Company does not support the "bring your own device" recommendation by witness Murray, unless or until such concerns are addressed. Id.

Summary of Post-Hearing Briefs

In its post-hearing Brief, EDF recommends that the Commission reject DEC's request for cost recovery for AMI meters, and require DEC to establish a regulatory asset for these costs until DEC can demonstrate cost-effectiveness of its AMI deployment. EDF states that customer data access is foundational to realizing the benefits of AMI meters and requests that the Commission require DEC to implement the data access recommendations of NCSEA witness Murray. EDF summarizes witness Murray's recommendations regarding access to usage data, and states that AMI meters will not be used and useful unless DEC implements witness Murray's recommendations.

EDF also cites Public Staff witness Floyd's testimony that the Public Staff's support of DEC's AMI cost recovery is conditioned on DEC providing "informational tools and applications that provide more granular and timely data to allow customers greater insight and control over their actual usage." Tr. Vol. 23, p. 90. EDF contends that witness

Murray's recommendations would fulfill this requirement. EDF further states that customer savings from full access to their usage data are quantifiable, and cites DEC witness Schneider's testimony that DEC quantified these benefits for Duke Energy's AMI deployments in Indiana and Kentucky.

In addition, EDF discusses DEC's pilot program to install a device that will receive energy usage data from the Zigbee radio in the customer's AMI meter and transmit the data, via the customer's home wi-fi system, to the customer's cell phone and computer. EDF criticized the fact that DEC will not provide similar data access to third parties or allow customers to purchase their own home energy monitors and synch them up with the AMI meter, stating that this pilot program violates the principle, established in DEC's service regulations, that DEC's electric service ends at the point of delivery, and discriminates by restricting customers to the use of a utility device in order to access their own data. EDF maintains that the Commission should require DEC to implement robust data access now, before DEC receives cost recovery for AMI meters. EDF, therefore, recommends that the Commission reject DEC's request for cost recovery and require it to establish a regulatory asset for AMI costs until DEC implements witness Murray's recommendations.

NCLM, in its post-hearing Brief, cites witness Coughlan's comparison of the time-of-use options offered by DEC and DEP as demonstrating the greater time-of-use offerings that DEP has without fully implementing AMI technologies and Power/Forward. In addition, NCLM cites Public Staff witness Floyd's concern that DEC will not immediately maximize the benefits available to customers of AMI, and his testimony that:

> [i]t will be incumbent upon DEC to maximize the benefits not only by eliminating or reducing expenses to provide utility service or NTLs, but also by providing new opportunities for customers to use both AMI meters and CCP so that they see a real benefit on their bills. Customers who are more aware of their energy use should be empowered to make more informed choices on how they use and pay for energy.

Tr. Vol. 23, p. 89.

NCLM states that complete deployment of AMI is not necessary for DEC to have discussions and receive input from customers on how to develop new rate designs, or to provide additional information to its current OPT-V customers. Moreover, NCLM contends that DEC should be required to increase its reporting on AMI and Customer Connect in order to provide more accountability. NCLM submits that the Commission should order DEC to provide its current time-of-use customers with additional information to maximize the benefits of load shifting, to develop proposals for new and innovative time-of-use and critical peak pricing rate designs and prepayment options before the next rate case, and to provide regular updates to the Commission about its progress in developing and deploying new rate designs.

In its post-hearing Comments, the City of Durham contends that ratepayers currently gain no benefits from AMI meters beyond the benefits received from DEC's used and useful AMR meters. Durham joins with NCLM in its request that the Commission order DEC to develop proposals for new and innovative time-of-use and critical peak pricing rate designs as soon as possible. Finally, Durham expresses concerns about the privacy implications of AMI two-way communications, and requests that the Commission consider ordering a study to be conducted on this issue.

Discussion and Conclusions

In the present docket, as part of DEC's general rate case application, DEC seeks to recover $90.9 million for AMI deployment in North Carolina from January through November 2017. "The requested increase in revenues related to AMI in this case includes a total of $11.2 million for return and depreciation related to this investment." Tr. Vol. 6, pp. 254-55. In addition, DEC requests authority to establish a regulatory asset account. The depreciation study recovers the remaining book value of these assets over 3 years; however, as the individual meters are replaced, DEC needs to move the retired meter balance into a regulatory asset account until the asset is fully depreciated. Id.

A. Reasonableness of AMI Costs

DEC witness McManeus testified regarding the costs of DEC's AMI deployment. Tr. Vol. 6, pp. 254-55. Further, in the SGTP Docket and the present docket, DEC has provided extensive information about its purchases of AMI meters and its costs of installing them. For example, the cost-benefit analyses include columns showing the capital and O&M costs of the AMI project. In addition, on March 26, 2018, at the request of the Commission, the Public Staff filed a late-filed exhibit that included a spread sheet provided by DEC in response to a Public Staff data request. In part, the exhibit shows that the total capital cost of DEC's AMI programs through September 2014 was $94.43 million, with $26.85 million having been provided by the DOE grant.

The Commission gives substantial weight to the above testimony and documentary evidence. In addition, no party has questioned the reasonableness of DEC's AMI costs. In State ex rel. Utils. Comm'n v. Intervenor Residents, 305 N.C. 62, 75-77, 286 S.E.2d 770, 778-79 (1982), the North Carolina Supreme Court held that the uncontested evidence of a public utility regarding the reasonableness of its costs can be accepted by the Commission as satisfying the utility's burden of proof on the question of cost recovery. As a result, the Commission finds and concludes that DEC has met its burden of showing that its AMI costs were reasonable. Public Staff witness Floyd testified:

> Except for the concerns I have raised concerning DEC's cost-benefit analysis, I believe the Company has made a reasonable assessment of the costs and benefits associated with its proposed deployment of AMI … I do not object to inclusion of the Company's AMI costs incurred to date and included in this filing.

Tr. Vol. 23, pp. 92-93. Therefore, the Commission authorizes recovery on the merits on the basis of these uncontested recommendations.

As described above in the details of the SGTP Docket, DEC has followed a studied and deliberate plan for installing AMI, including the AMI Phase 1 and Phase 2 projects, and the AMI Expansion 2015 project. With regard to AMI Phase 1 and 2, DEC explained that it initiated the project in 2013. Leveraging grant funds from DOE, DEC replaced aging AMR with AMI in North Carolina and South Carolina. Phase 2 was completed in the first quarter of 2015, bringing the total of installed AMI meters to about 313,500 in North Carolina. In DEC's AMI Expansion 2015, DEC pursued a limited-scope AMI project to install approximately 181,000 AMI meters to serve residential customers in the Charlotte Metro area. That project was completed in July 2016. As of September 2016, DEC had cumulatively installed about 527,391 AMI meters. After gaining substantial knowledge about AMI provided by the installation of more than 500,000 AMI meters, DEC made a decision in late 2016 to begin full scale deployment of AMI in North Carolina, and began implementing that decision in early 2017.

The Commission gives substantial weight to the above evidence. AMI is a new technology. Maintaining adequate and reliable electric service includes staying abreast of the latest developments in equipment and technology. Indeed, advances in technology can provide efficiencies and other benefits that justify retiring present equipment. After having deployed AMI on a project-by-project basis for several years, it was reasonable and prudent for DEC to use that experience to decide to deploy AMI on a full scale.

In DEC's Supplemental Filing in the SGTP Docket, DEC discussed the possibility of additional customer services to be provided by AMI.

> [A]MI is the foundational investment that will enable enhanced customer solutions – giving customers greater control, convenience and choice over their energy usage, while also giving customers the opportunity to budget, save time and money. AMI technology allows a utility to gather more granular usage data and utilize new capabilities to offer new programs and services to customers that are not achievable through existing meters. The AMI technology will pave the way for programs that will allow customers to stay better informed during outages, control their due dates, avoid deposits, to be reconnected faster, and to better understand and take control of their energy usage, and ultimately, their bills. Over time, the Company also expects AMI meters to contribute to cost reductions from reduced truck rolls in the years after deployments.

Supplemental Filing, p. 1.

In addition, during redirect examination by DEC’s counsel witness Schneider stated:

> [t]here is a lot of additional customer programs and benefits that the AMI, as a foundation, enables that, again, we didn’t have those costs and benefits in

> our cost-benefit model because they just weren't designed yet. We didn't know what the costs were in each of those cases, you know, will be on their own. So in general, with a positive business case, and plus the fact that we know there is additional customer products and services that this solution can enable, the Company has made a decision that this is a viable project that we want to move forward with.

Tr. Vol. 18, pp. 413-14.

The Commission gives substantial weight to the above evidence. The AMI benefits, current and future, identified by DEC are substantial. It was reasonable and prudent for DEC to rely on these AMI benefits in deciding to deploy AMI on a full scale.

However, the Commission also agrees with NCLM, EDF and others that DEC should be required to follow through on designing and proposing new rate structures that will capture the full benefits of AMI. Therefore, the Commission finds and concludes that DEC should within six months of the date of this Order file in this docket the details of proposed new time-of-use, peak pricing, and other dynamic rate structures that will, among other things, allow ratepayers in all customer classes to use the information provided by AMI to reduce their peak time usage and to save energy. The Commission's goal is to require DEC to develop rate structures now that will enable DEC to deliver on its promise that there are "additional customer products and services that this solution [AMI] can enable" no later than DEC's next general rate case. Further, the Commission hereby gives DEC notice that DEC's success, or lack thereof, in developing new rate structures that enable AMI energy usage benefits will be one of the factors used by the Commission in determining the prudence and reasonableness of DEC's costs incurred in deploying AMI following the present rate case. In addition, as discussed subsequently herein, the Commission has directed DEC to continue working with the Public Staff, EDF and other interested parties to develop guidelines for access to customer usage data.

As noted above, the two cost-benefit analyses produced mixed results regarding the net present value of the costs and benefits of AMI. As a result, the Commission finds that the results of these analyses are not helpful in determining the benefits to be derived from AMI. Therefore, the Commission gives little weight to the conclusions of the cost-benefit analyses as to the net present value of AMI benefits and costs.

No party provided substantial evidence of a lack of prudence by DEC in its decision to deploy AMI. Although the Public Staff and EDF levied some general criticisms of DEC's cost-benefit analyses, they offered no concrete or probative evidence as to why the costs should not be recovered or a lack of reasonable decision making by DEC. Indeed, the Public Staff concluded that DEC made a reasonable assessment of AMI and, therefore, the Public Staff did not object to DEC's recovery of its AMI costs.

Based on the substantial evidence of DEC's project-by-project deployment of AMI for several years, and the current and future AMI benefits identified by DEC, the

Commission concludes that a preponderance of the evidence shows that DEC's decision in early 2017 to fully deploy AMI was a prudent decision.

B. Appropriate Remaining Useful Life for AMR Meters

DEC's 2017 SGTP Update showed that the remaining net book value of its AMR meters was an estimated $127.66 million as of March 31, 2017. However, in the SGTP presentation witness Schneider testified that DEC would receive tax benefits that would reduce the lost book value to approximately $85 million. SGTP Presentation. DEC proposes in its depreciation study to recover the remaining net book value of the AMR meters over three years. Public Staff witness Maness does not oppose the establishment of a regulatory asset account to track the retirement and remaining depreciation of the replaced meters, but he opposes customers being charged the entire cost over 3 years. Public Staff witness Maness testified that DEC's existing AMR meters have an average remaining useful life of 15.4 years, and that 15.4 years should be used as the remaining useful life when developing depreciation rates.

DEC's deployment of AMR meters was a reasonable and prudent decision that helped DEC and its ratepayers capture the benefits of new metering technology at that time. Likewise, the Commission has determined that DEC's deployment of AMI today is a reasonable and prudent decision. Further, the Commission gives significant weight to the Public Staff's position that DEC should be allowed to recover the remaining book value of is AMR meters, but that the remaining useful life should be for 15 years, rather than the three years as requested by DEC.

With regard to EDF's recommendation to place AMI in a new docket, the Commission concludes that the current SGTP docket is the appropriate docket in which to obtain information and review the electric utilities' AMI plans. Moreover, the Commission finds and concludes that the potential benefits and risks of the "bring your own device" program advocated by NCSEA witness Murray can be studied and discussed in the meetings ordered in Docket No. E-100, Sub 147 regarding access to customer usage data.

In summary, the Commission finds good cause to grant DEC's request to recover its AMI costs. Further, the Commission finds good cause to require DEC to within six months of the date of this Order file proposed new time-of-use, peak pricing, and other dynamic rate structures that will, among other things, allow ratepayers in all customer classes to use the information provided by AMI to reduce their peak time usage and to save energy. Finally, the Commission finds and concludes that DEC may establish a regulatory asset to track the retirement and remaining depreciation of AMR meters, but DEC shall use a 15-year remaining useful life in its depreciation study.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 41

The evidence supporting this finding of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, Docket No. E-100, Sub

147, the testimony of DEC witness Hunsicker, EDF witness Alvarez, and NCSEA witness Murray, and the entire record in this proceeding.

NCSEA witness Murray testified that DEC should provide customer usage data information, recorded by AMI, to customers and authorized third parties; provide historic use and current rate data to customers and authorized third parties in machine readable (xml) format; and establish a customer authorization process. Tr. Vol. 26, pp. 400-02. Both witness Murray and EDF witness Alvarez recommended that the Commission consider providing the energy usage data to customers and third parties through Green Button Connect My Data (GBC), a nationally standardized and automated method. Id. at 326-27, 412. According to witness Murray, a principal advantage of GBC is that consumers can automatically transmit data to third parties without having to purchase additional metering equipment for their home or building. Id. at 412.

In her rebuttal testimony, Company witness Hunsicker testified that DEC agrees with and defers to Public Staff witness Floyd's recommendation in his testimony to protect customer data and adhere to the Code of Conduct as it relates to the sharing of customer information. Tr. Vol. 18, p. 278. Witness Hunsicker further testified that providing third parties with access to consumption and load profile, which witness Murray recommends, would violate the prohibition against disclosing customer information to third parties. Id. According to witness Hunsicker, customers already have access to historic usage data in the form of bills and via the Company's external website, and that the Company plans to assess the possibility of providing usage information to customers using certain "Green Button" programs. Id. At the hearing, witness Hunsicker opined that customers have a basic right to access their usage data, but explained that the Company compiles the data and analyzes it using Company software, which creates a co-ownership of the data. Id. at 310. Witness Hunsicker further testified that the Company takes no issue with providing the capability for third party access to customer data, provided the following requirements are met: (1) the costs for the platform are borne by the participating customers; (2) the implementation of the platform has no impact on the Company's system or data security; (3) the appropriate customer and regulatory consents are complied with, including the Code of Conduct; and (4) the ongoing monitoring of the additional platform does not become disruptive of the Company's daily operation. Id. at 299-300. However, witness Hunsicker expressed particular concerns with providing data directly to third parties via an automated process due to the possibility of physical security risks resulting from increased third-party access to customer usage data and the potential for third parties to create customer confusion and possibly misrepresent their affiliation with the Company. Id. Witness Hunsicker stated that the Company looks forward to discussing these issues in more detail in the meeting to discuss guidelines for access to customer usage data, as directed by the Commission in its March 7, 2018 Smart Grid Technology Plan Update Order in Docket No. E-100, Sub 147. Id.

The Commission appreciates the recommendation of NCSEA and EDF regarding the collection and dissemination of customer usage data. However, the Commission is not persuaded that this is the time or the proceeding in which to impose such requirements on the Company. As witness Hunsicker testified, the Commission and interested parties are addressing issues regarding access to customer usage data in Docket No. E-100, Sub 147. In that docket, on March 7, 2018, the Commission issued an order on DEC's and DEP's (collectively, Duke's) 2017 Smart Grid Technology Plan (SGTP) Updates that included the following directive on access to customer data:

> [T]herefore, the Commission finds good cause to direct that Duke convene and facilitate discussions with NCSEA, the Public Staff, and other interested parties on this topic, with the goal of reaching agreement on all aspects, or as many aspects as possible, of the rule proposed by NCSEA. In addition, the Commission requests that the discussions include the Green Button Connect My Data system for data access. The Commission further directs that Duke provide the Commission a report detailing the discussions, agreements reached on particular points, points on which agreement has not been reached, and the barriers to agreement on remaining points, as well as the parties' plans for further discussions. The report shall be filed in Docket No. E-100, Sub 147 no later than 30 days after the first meeting of the stakeholder group. Further, the Commission directs Duke to reflect the results of these discussions in its 2018 SGTP reports.

2017 SGTP Order, at 10.

As a result, the Commission declines to adopt NCSEA's and EDF's proposal at this time.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 42-44

The evidence supporting these findings of fact and conclusions of law is found in the Application, the Stipulation, and the entire record in this proceeding, particularly the testimony and exhibits of the following expert witnesses: DEC witnesses Fountain, McManeus, and Simpson, Public Staff witnesses McLawhorn, Williamson, Parcell, and Maness; Commercial Group witnesses Chriss and Rosa, CIGFUR III witness Phillips, Kroger witness Higgins, EDF witness Alvarez, NCSEA witnesses Barnes and Golin, Tech Customers witness Strunk; and CUCA witness O'Donnell.

The expert witness testimony and exhibits regarding Duke's Power Forward Carolinas initiative (Power Forward) and DEC's request for special ratemaking treatment of Power Forward costs is voluminous. The Commission has carefully considered all of the evidence and the record as a whole. However, the Commission has not attempted to recount every statement of every witness. Rather, this Order provides a thorough summary of the evidence.

Likewise, the Commission has read and fully considered the parties' post-hearing briefs. However, the Commission has not in this Order expressly addressed every contention advanced or authority cited in the briefs, almost all of which address Power Forward or the Grid Rider in some fashion. Based upon the evidence and reasons addressed below, the Commission determines that DEC's request to establish a Grid

Rider or, in the alternative, to allow deferral accounting of Power Forward costs through the establishment of a regulatory asset, should be denied.

Summary of the Evidence

DEC's direct testimony

Company witness Fountain testified that Power Forward is Duke's decade-long, $13-billion grid modernization plan for Duke Energy Progress, LLC (DEP), and DEC, in each of their respective North Carolina service territories. Of the $13 billion in total Power Forward spend by DEC and DEP on Power Forward programs, DEC plans to spend $7.7 billion, including $2.9 billion in capital and $130 million in operations and maintenance (O&M) expense during the first five years. Witness Fountain testified that the purpose of Power Forward is to improve the performance and capacity of the grid, thereby making it smarter, more resilient, and better able to provide benefits to customers.

DEC Witness Simpson described generally the programs comprising Power Forward, including (1) targeted undergrounding, (2) distribution system hardening and resiliency, (3) self-optimizing grid technology, (4) transmission system improvements, (5) Advanced Metering Infrastructure (AMI)[28], (6) communication network upgrades, and (7) advanced enterprise systems. According to witness Simpson, these programs will primarily focus on projects that accomplish the following goals: improve the reliability and hardiness of the system while making it smarter, build a foundation for customer-focused innovation and new technologies, comply with prescriptive federal transmission reliability and security standards, address maintenance requirements for aging assets, further integrate and optimize intermittent distributed renewable energy generation, and address physical and cyber security, worsening weather, customer disruption, and wear and tear on equipment.

Power Forward investments are planned to supplement customary spend on the transmission and distribution (T&D) grid. To pay for Power Forward programs, DEC proposes that the Commission establish a Grid Reliability and Resiliency Rider (Grid Rider) to "more closely align … [Power Forward] investments … with the timeliness of recovery for these investments." Tr. Vol. 6, p. 193. According to witness Fountain, the Grid Rider "would be reset annually based on actual costs, with a true up for any over- or under-recovery." Id. Turning to the mechanics of the Grid Rider, witness Fountain testified that an annual rider proceeding would be held, at which DEC "would provide the specific projects that would be reviewed and approved and the scope of work and things like that." Tr. Vol. 9, p. 78.

On cross-examination, witness Fountain testified that DEC did not initially submit direct testimony regarding the rate impact of the proposed Grid Rider, although he later testified that the net average retail impact would involve a 16% rate increase over the

[28] Although AMI is a Power Forward program, Company witness Simpson testified on rebuttal that DEC is not proposing to recover AMI-related costs through the Grid Rider.

10-year Power Forward plan. He also testified that DEC plans to invest in Power Forward programs regardless of whether the Grid Rider is approved, but that such investments would likely happen more slowly if the Grid Rider is not approved. Witness Fountain conceded that electricity demand growth is currently "not as much as in prior decades." Tr. Vol. 6, p. 432. Witness Fountain also admitted that Power Forward is part of Duke Energy's corporate policy intended, as quoted in a Duke investor earnings call, "to drive 4 to 6 percent earnings growth." Id. at 434. He acknowledged that Duke Energy represented to its investors that it would pursue distribution infrastructure riders to enhance investment returns, and that the addition of new riders to the ratemaking regulatory framework is intended to "recover [Power Forward] investments in ways that are good for customers as well as help drive shareholder value." Tr. Vol. 8, p. 211. He further conceded that DEC already has made a number of investments without the aid of a rider, including to transition DEC's grid from analog to digital technology through AMR meters.

Company witness McManeus testified that the Grid Rider would allow DEC to recover Power Forward costs on an annual basis after projects are deployed and closed to plant in service, as opposed to the traditional method of recovering costs through a general rate case. She testified that the Grid Rider would help to avoid some dilution of cash flow and earnings, which could slow the pace of the planned investments. The Grid Rider would be set based on "a projection of revenue requirements," combined with a true-up or "Experience Modification Factor" (EMF) for a prior test period. Tr. Vol. 6, p. 271. The Grid Rider would supplement rate changes implemented in general rate cases, with amounts not recovered through the Grid Rider to be included in base rates during the next rate case proceeding. Witness McManeus filed a late-filed exhibit on April 19, 2018, indicating that DEC is seeking to recover $35.2 million through the Grid Rider for 2018 Power Forward spending. Witness McManeus also requested that, in the event that the Commission does not approve the Grid Rider, a regulatory asset be established to defer Power Forward costs for future recovery in a general rate case.

In rebuttal testimony, witness McManeus acknowledged that the Grid Rider would result in "an annual 'mini-rate case' proceeding" limited in scope to costs incurred in connection with Power Forward. Id. at 333. She further testified that the Commission could take action if, as a result of the Grid Rider, DEC's earnings at some future point grew such that they are no longer just or reasonable. Therefore, she testified, the Grid Rider would not "definitively create[] the opportunity for the Company to over earn." Id. at 334. On cross-examination, witness McManeus acknowledged a number of times that the Grid Rider would pass only costs on to ratepayers, but would not account for cost savings resulting from improvements to the grid. She explained that "the reason that the Company requests a rider is to address the issue of regulatory lag that exists in any general rate case proceeding … that would have the adverse effect of reducing cash flows and earnings." Id. at 440-41. She also conceded that approval of the Grid Rider "would eliminate some regulatory lag, but not necessarily a lot," and would mitigate some regulatory risk for DEC. Tr. Vol. 7, pp. 33-34. Witness McManeus further testified on cross-examination that the planned Power Forward spend described in DEC's filings is not granular data at the project level, but instead is in "large buckets" that correspond to

FERC accounting categories. Tr. Vol. 9, p. 74. She conceded that the proposed 2018 Power Forward spending is based on "the same information." Id. at 76.

Company witness Simpson testified that Power Forward is a collection of programs that include projects to upgrade the Company's T&D grid. Witness Simpson testified that DEC provides service to approximately 2 million customers in North Carolina, where the Company has more than 100,000 miles of lines and over 1,600 substations. He indicated that in the last four years, the Company has spent $2.6 billion to maintain and upgrade DEC's T&D grid: $1.8 billion in distribution system investments and $770 million in transmission system investments. Distribution investments include connecting new customers, installing lights, adding capacity, and upgrading and maintaining infrastructure, while the Company's transmission investments include addressing capacity and compliance projects, as well as replacing wood poles, obsolete substations, and line equipment. Witness Simpson discussed the need for the Company to continue its customary T&D spending, in addition to Power Forward spend to be recovered through the Grid Rider. He stated that the Company anticipates customary T&D expenditures over the next five years to amount to $3.4 billion.[29]

Witness Simpson testified that Power Forward is necessary because of more frequent convective weather events, aging components, and the addition of more distributed energy resources (DER). While weather is something that the Company has always dealt with in maintaining electric service, witness Simpson stated that more frequent severe weather events drive worsening reliability metrics and that, in his opinion, enhanced hardening of the grid will improve the overall reliability of the grid. Even with more frequent extreme weather events, witness Simpson admitted that the distribution of root causes for outages will remain the same in terms of the number and types of events: 20% for vegetation management related outages, close to 20% for equipment failure, and 6-10% for public accidents, with only the minutes per interruption increasing.

As for the wear and tear on and age of T&D equipment, witness Simpson stated that while Power Forward is not about "chasing aging assets," the current electric grid was built 40 to 60 years ago, and is aging. Tr. Vol. 17, p. 34. Although not a new revelation to the Company, 30% of its T&D assets will be beyond their useful life in the next ten years; not even the best maintenance can stop the cumulative effects of age on the system. Witness Simpson acknowledged that the grid has evolved over decades, and is more hardened today in terms of quality of design than it used to be.

Witness Simpson described the Targeted Undergrounding program as using data analytics to identify line segments with degraded multi-year reliability performance when compared to overhead facilities, in total. Witness Simpson agreed in his rebuttal testimony that taking overhead lines and putting them underground is not a new technology and has been part of utility reliability improvement efforts for years. However, he asserted that the

[29] Witness Simpson originally projected $4.5 billion in customary T&D spend over the next five years. In his rebuttal testimony, however, witness Simpson lowered that projection by $1.1 billion, to reflect the removal of certain costs linked to Power Forward programs, which DEC now proposes to recover through the Grid Rider instead of through customary spend recovered through a general rate case.

Targeted Undergrounding program is unique because of the data analytics which the Company now employs to determine which individual line segments (versus entire circuits) to underground. Witness Simpson stated that the Company is not talking about a massive undergrounding project but rather targeting specific poorly performing line segments to be undergrounded, which now can be determined in minutes and hours as a result of new analytic capabilities, as opposed to the days and weeks it took in the past. Witness Simpson conceded, however, that using data analytics to determine how parts of the grid are performing is not a new concept, and is something that has been evolving for decades, and that will continue to evolve in the future.

According to witness Simpson, the Distribution Hardening and Resiliency program includes retrofitting transformers to eliminate common outage causes, replacing aged or deteriorating cable and conductors, and providing back feed capability to vulnerable communities. Witness Simpson testified that within Power Forward's Distribution Hardening and Resiliency Program, there are four categories of projects that are included in both the Power Forward budget and the Company's customary T&D reliability and integrity and maintenance programs. These four categories of projects are transformer retrofit, underground cable replacement, deteriorated conductor replacement, and targeted pole hardening. Witness Simpson stated that these categories only account for 10% of Power Forward spend and also testified that they constitute the only overlap between the Company's customary spend and Power Forward spend. Witness Simpson argued that these projects should be included in the Grid Rider due to the pace of the expenditures rather than the classification of the investment.

Witness Simpson explained that the Transmission Improvements program includes projects to update and replace transmission system equipment that is likely to fail in the near future, and to add systems that will notify the Company of problems before they result in an outage. The program also will include pole replacement, line rebuilds, substation animal mitigation, and other unspecified physical and cyber security improvements. Witness Simpson stated that this program expedites replacement of obsolete and old design equipment, replacing such equipment with newer equipment that will allow for improved proactive monitoring of the transmission system. Witness Simpson testified that while there is some remote proactive monitoring today, it is not uniform across the system, and the Company has not invested enough in the most current technology to provide a system-wide picture. DEC will consider which substations need upgrades to reach the Company's desired level of functionality. Another category of projects addressing substations is animal mitigation. Witness Simpson conceded that the Company has historically addressed animal mitigation, but contended that many substations still need these upgrades due to national security issues.

Witness Simpson testified that the Self-Optimizing Grid program will add redundant capacity to distribution circuits and substation transformers by replacing existing facilities with larger conductor cable and tying radial distribution circuits together with automated switches to create a distribution network and facilitate two-way power flow. Witness Simpson asserted that this effort also will make the grid "stiffer," allowing for more

DER to be connected. Witness Simpson acknowledged, however, that adding redundant lines for back-feed or tie-ins is something that the Company has previously done.

Witness Simpson testified that the investment in Power Forward will be above the Company's customary spend, which he acknowledges is a spending level set by the Company based on projections of the costs necessary to maintain a reliable grid. Witness Simpson itemized the Company's customary distribution capital expenditures over the last four years as follows: 55% for expansion-related work, including serving new customers, lighting installations, and additional capacity; 22% for infrastructure maintenance activities such as pole replacement and underground cable replacement; 23% for targeted reliability improvements to reduce the number and frequency of power outages on the distribution system, including the transformer retrofit program, the sectionalization program, and self-healing technology to automatically isolate the cause of an outage and restore service to customers.

Witness Simpson testified that the Company needs to continue its customary investments in the T&D system to maintain the grid and to add new customers, for which DEC originally budgeted to spend $4.5 billion from 2017-2021. On rebuttal, however, witness Simpson clarified that the estimated customary spend level of $4.5 billion in fact included $1.1 billion that was for grid modernization before Power Forward was developed. The Company then moved that forecasted amount for grid modernization out of the projected plant in service account, where customary T&D expenses are found, and into an account set up for Power Forward expenditures following the announcement of Power Forward. Therefore, DEC now projects customary T&D spend of $3.4 billion, in addition to approximately $3.03 billion of projected Power Forward costs, comprised of $2.9 billion in capital and $130 million for O&M, to be spent between 2017 and 2021. The movement of the $1.1 billion from the customary plant in service account to the Power Forward account was illustrated during the hearing by a project that was part of the original grid modernization fund of $1.1 billion that was in the customary plant in service account. Witness Simpson conceded that the Company had initiated construction of, and placed into service, certain projects that were included in capital forecasting prior to the announcement of Power Forward, but because the cost of the projects had not yet been recovered, they were moved into the Power Forward account to be recovered through the Grid Rider.

On cross-examination, witness Simpson testified that the Company's reliability metrics typically vary from year to year, and conceded that DEC actually saw an improving trend from 2003 to 2012 without the implementation of a Power Forward-type program or a rider. As to the distinction between Power Forward spend and customary spend, witness Simpson testified on cross-examination that a layperson or even an engineer from an electric cooperative may not be able to distinguish Power Forward construction from customary spend construction, but that DEC would know which is which. Witness Simpson further testified that, even where DEC has identified specific amounts for the Targeted Undergrounding program, it has not yet actually decided which locations or how much of the system will be undergrounded. He also testified that DEC would proceed with Power Forward as planned, within the same time frame, even without approval of the Grid Rider.

Alternatively, if the Commission does not approve the Grid Rider, witness McManeus testified that DEC "requests approval to defer as a regulatory asset the O&M (including income and general taxes) and capital-related costs (depreciation and return) associated with [Power Forward] for recovery in a future general rate case proceeding." Tr. Vol. 6, p. 273.

Company witness Pirro testified about DEC's proposed rate design for the Grid Rider. He explained that cost recovery through the Grid Rider, if approved, would follow standard ratemaking principles and would reflect rates that differ by rate class to attribute cost responsibility to each respective class consistent with the COSS supported by witness Hager. However, for reasons set forth hereafter, the Commission is denying DEC's request to establish the Grid Rider, this effectively rendering moot the issues of cost allocation or rate design of the would-be rider.

Public Staff testimony

Public Staff witness Williamson testified that the Public Staff does not support the establishment of the Grid Rider or deferral accounting for Power Forward costs because the Public Staff is not persuaded that all of the components of Power Forward will result in modernization of the grid, as opposed to DEC satisfying its every day statutory obligation to provide adequate and reliable service to its customers. Witness Williamson further stated that much of the Power Forward initiative is designed to improve DEC's outage frequency and duration metrics, which should be part of DEC's every day planning and operations.

Witness Williamson described the Company's proposal as incredibly wide in scope with many disparate parts and elements. Witness Williamson further testified that if the Commission decides to approve a rider for Power Forward, then the Targeted Undergrounding program costs should not be recovered through the rider because the undergrounding of lines for reliability purposes is not new, modern, extraordinary, or outside the scope of normal operations required to provide adequate and reliable service to customers. He went on to state that the Distribution Hardening and Resiliency program also includes many projects that are customary T&D projects, such as cable and pole replacement. The Commission analyzes in more detail the Public Staff's position that Power Forward programs are not unique or extraordinary, and should therefore be considered routine, customary spend to be recovered through a general rate case, in its determinations hereafter.

In 2003, the Public Staff prepared a report on the feasibility of undergrounding the State's entire distribution grid for the North Carolina Natural Disaster Preparedness Task Force (2003 Report). Tr. Ex. Vol. 24, pp. 116-164. The 2003 Report found that undergrounding the entire distribution grid was too costly and recommended instead that each utility (1) identify the overhead facilities that repeatedly experience reliability problems; (2) determine whether conversion to underground is a cost-effective option for improving the reliability of those facilities; and, if so, (3) convert those facilities to underground.[30]

Regardless of whether the Grid Rider is approved, witness Williamson recommended that the Commission require DEC to include in its annual Smart Grid Technology Plan filings, required by Commission Rule R8-60.1, more detailed information on (1) the purpose of each project or category of projects, (2) a schedule of implementation, (3) changes to the schedule that would impact the project's cost or in-service date, (4) project capital and O&M costs (both new and any stranded costs of removed assets), (5) how the Company proposes to recover these costs, and (6) a demonstration of how the project is designed to reduce the outage frequency and duration of individual circuits or other T&D assets affected by the project.

Public Staff witness Maness stated that any time the Commission segregates one item or a group of items for single-item ratemaking, either through a rider or through deferral accounting, it upsets the regulatory balance in that the "incentives restraining capital investment that are naturally present in the normal aggregated method of ratemaking under [N.C. Gen. Stat. §] 62-133 are relaxed, because the only thing restraining the utility from making these types of investments is the ability of the regulator to devote precious resources to eliminate any imprudent or unreasonably large costs." Tr. Vol. 22, p. 92. In addition, "splitting out major items for single-item ratemaking can make it more likely that the Company will exceed its allowed or appropriate overall rate of return." Id. Witness Maness testified that, as with riders, deferral accounting is an exception to the general method by which rates are normally set for North Carolina's electric public utilities. Rates are normally set on the basis of the aggregate amount of the utility's expenses, revenues, and rate base, and a consideration of the rate of return produced by that aggregation of costs and revenues. Specific components of revenues and costs fluctuate over time, and increases in one cost component can often be offset by decreases in another, thus perhaps mitigating the need for a rate increase to provide recovery of the increase in cost of the first item. He explained that this is one of the reasons that the Commission has previously stated that deferral accounting and riders should be the exception, not the rule. Witness Maness stated that it is important that items set aside for special ratemaking treatment be both extraordinary in magnitude and very unique in type. In addition, witness Maness testified that when a rider or deferral accounting is established, costs intended to be included in the rider should be easily identifiable because of the issues and controversies that may arise regarding specific items of costs and their respective eligibility for special ratemaking treatment. Witness Maness agreed with Public Staff witness Williamson that the types of plant items that the Company is proposing for inclusion in the Grid Rider are vaguely described.

Public Staff witness Parcell testified that DEC's proposed Grid Rider shifts risk from the Company to its ratepayers in that the possibility that certain Power Forward expenses

[30] Company witness Simpson admitted that the Company had not performed any undergrounding of distribution lines in response to the Public Staff's recommendation in the 2003 Report.

would be disallowed by the Commission would be reduced or eliminated. Witness Parcell quoted a report by Moody's Investors Service, stating in part that it views "the use of rider/tracking mechanisms as positive for credit as they reduce regulatory lag and improve the predictability and stability of cash flow." Tr. Vol. 26, p. 830. Public Staff witness Parcell testified that it is important to consider a rider's effect on the cost of equity for a utility and, accordingly, its rate of return on equity.

Testimony of other intervening parties

CIGFUR III witness Phillips testified that the proposed Grid Rider would shift regulatory risk from investors to customers, and may also eliminate DEC's incentive to prudently manage costs between base rate cases. Additionally, witness Phillips contended that Power Forward costs are not volatile or unpredictable, but rather are within the Company's control and, therefore, are not appropriately recovered through a rider. He stated that DEC has an obligation to provide safe and reliable electric service, and consequently, that Power Forward investments are likely to be made with or without approval of the Grid Rider. Witness Phillips stated that the Company has not demonstrated that the Grid Rider is necessary. As such, he recommended that the Grid Rider be rejected. In the alternative, if the Commission approves the Grid Rider, witness Phillips asserted that the Company's "allowed ROE should be reduced to reflect the reduced business risk that investors will face." Tr. Vol. 26, p. 277. Similarly, Tech Customers witnesses Chriss and Rosa asserted that the Grid Rider would reduce risk for the utility, and that this should be considered when setting DEC's rate of return on equity.

CUCA witness O'Donnell testified that the Grid Rider should be disallowed because, in his opinion, it is too expensive and is likely to harm the North Carolina economy. Witness O'Donnell also testified that DEC has been transparent about the purported benefits, but not the costs, of Power Forward. Witness O'Donnell testified that the Grid Rider is unnecessary because the Company can, and already is, investing in T&D equipment, with the only difference being that it has had to seek recovery of those investments through its general rate cases instead of an annual rider proceeding. Witness O'Donnell testified that DEC's lobbyists unsuccessfully attempted to have legislation enacted that would create the Grid Rider by statute.[31]

Witness O'Donnell stated that the Commission should open a separate docket to investigate the need for DEC's proposed grid investments and to allow for transparency and public involvement in the examination of the following issues: (1) whether Power Forward is needed for reliability purposes; (2) the benefits of Power Forward; (3) the costs of Power Forward; (4) whether Power Forward is cost-effective; (5) how other states are handling grid modernization issues; (6) lessons learned from other states; (7) how North Carolina's renewable energy industry will be affected by Power Forward; and (8) how the rate increases expected under Power Forward and the Grid Rider will affect the State's economy.

[31] See Senate Bill 619 (2017).

Witness O'Donnell further testified that the Company's objective is to drive earnings through Power Forward investments and that the Company seeks to shift risk onto consumers by asking for an automatic forward-looking cost recovery mechanism such as the Grid Rider. In addition, witness O'Donnell expressed concern that the Commission would not retain full regulatory review of Power Forward programs in the Grid Rider's annual proceeding. He stated that during such a proceeding, the ratepayer, and not the utility, would have the burden of proving that DEC's costs were not reasonably or prudently incurred.

While EDF witness Alvarez acknowledged that he is generally supportive of utility grid modernization efforts, he stated that the Commission should deny DEC's request for the Grid Rider until after the Commission has opened a separate proceeding to review, with stakeholder participation, whether Power Forward is warranted for the following reasons: (1) grid modernization investments are very large and distinct in character from business-as-usual investments; (2) Commission review with stakeholder participation will better align DEC's grid modernization investments with Commission and State priorities; (3) applying the "used and useful" standard to assess the prudence of grid modernization investments after the fact is inadequate to protect consumer and environmental interests; (4) disallowance of cost recovery could harm the utility's ability to finance future growth, making it impractical and difficult for the Commission to deny cost recovery once grid modernization investments have already been made; and (5) a Commission review process would likely result in a better cost-benefit ratio for grid modernization programs than if no such review were conducted.

Kroger witness Higgins testified that the Commission should disapprove the Grid Rider because, in his opinion, infrastructure investments should be evaluated in the context of a general rate case, wherein the totality of DEC's revenues and costs for a given test year are analyzed. He testified that investing in and maintaining the T&D system are fundamental responsibilities for a utility company and, therefore, the related costs should continue to be evaluated as part of a general rate case.

NCSEA witness Barnes testified that the Commission should disapprove the Grid Rider, and instead initiate a separate proceeding to fully investigate Power Forward. Witness Barnes testified that he is concerned about the proposed Grid Rider cost allocation, particularly in light of cost causation principles. Furthermore, of the total revenue requirement to be borne by residential customers, the majority would be recovered as a fixed monthly charge. Witness Barnes stated that the Grid Rider appears to be the first step toward a series of both fixed and variable rate increases for several years to come.

NCSEA witness Golin recommended that the Commission deny the Company's proposal to recover Power Forward costs through either the Grid Rider or deferral accounting. She stated that the Commission should instead open a stand-alone docket to thoroughly define and plan for a modernized grid. In so doing, witness Golin stated that the Commission should require DEC to conduct robust distribution resource planning and take a holistic view of the grid and the technologies that are capable of meeting the grid's needs. This, according to witness Golin, would assure proper forecasting, better evaluate the role of distributed energy resources, and allow for increased transparency and stakeholder input. "Distribution resource planning should be accompanied by thorough cost/benefit analyses that compare several investment pathways to meeting grid investment goals." Tr. Vol. 14, p. 70. Witness Golin recommended that, as part of a new proceeding to examine Power Forward, participants could determine a method and timeline for calculating and publishing the distributed generation hosting capacity of DEC's distribution circuits. Witness Golin also advocated that the Commission open a new docket or stakeholder working group "to assess the impacts of shifts in the Company's investment strategy with the current mechanisms for cost recovery and implications for rate design." Id.

NCSEA witness Golin testified that the Company has not made clear how or why some investments fall under customary spend, and thus are recovered through traditional general rate case proceedings, and other investments fall under Power Forward, and thus would be recovered through the Grid Rider. Witness Golin testified that the Company has also failed to delineate a clear decision-making procedure for how it determined which capital investments are routine, and thus customary spend, and which investments fulfil the goals of the Power Forward initiative, and thus would be Power Forward spend.

Witness Golin further opposed the Grid Rider because, in her opinion, riders allow utilities to obfuscate the risk of large capital investments, whereas DEC's shareholders would continue to bear the risk of investing in these projects if DEC is required to recover Power Forward costs through a general rate case. Witness Golin also opposed the Grid Rider because, in her opinion, it would harm the markets for energy efficiency and distributed energy resources.

Tech Customers witness Strunk testified that DEC failed to distinguish its planned Power Forward spending from customary T&D investments. Describing the significant overlap between Power Forward investments and customary T&D spend, witness Strunk identified the risk that DEC will pursue the recovery of ordinary T&D costs through the Grid Rider. He testified that the Grid Rider threatens to unbalance the regulatory process by moving large capital investments outside of the general rate case process. Witness Strunk testified that the Grid Rider is unnecessary to reduce regulatory lag, in part because both DEC and the Commission have other means of addressing such lag. Witness Strunk testified that DEC's proposal is distinguishable from grid modernization trackers employed in other jurisdictions in that the Grid Rider fails to clearly identify eligible assets, it contains no spending cap on Power Forward investments, and it fails to recognize any offsetting cost savings. Witness Strunk criticized the Ernst & Young study commissioned by DEC as flawed because, in his opinion, the study focused on indirect benefits, excluded analysis of rate impacts, and lacked a clear showing of what DEC contends to be a deteriorating trend in reliability metrics.

DEC's rebuttal testimony

In response to some intervenors who argued that Power Forward is unnecessary and not cost-effective, witness Fountain cited to the study by Ernst & Young, commissioned by DEC, and testified that North Carolina will see net economic benefits from Power Forward's direct capital investments, ranging from $240 million to $1 billion. In response to concerns and questions about the long-term rate impacts of Power Forward, witness Fountain provided DEC Fountain Redirect Exhibit 1, showing that by 2026, Power Forward costs would cause rates to increase by 25.24% for residential customers, 12.39% for commercial customers, and 6.52% for industrial customers.

In response to Public Staff witness Williamson's suggestion that DEC be required to file additional information about Power Forward as part of its annual Smart Grid Technology Plan, witness Simpson testified that the Company is agreeable to the six reporting requirements recommended by the Public Staff, but opposes adding the requirements as a result of this rate case because Commission Rule R8-60.1 affects other utilities besides DEC.

In response to Public Staff witness Williamson's position that the Company has provided insufficient detail to warrant recovery of Power Forward costs through the Grid Rider, witness Simpson testified that the Company has provided economic and technical analyses, in addition to responding to more than 250 data requests regarding its Power Forward plans. Furthermore, in response to several intervenors' concerns, witness Simpson testified that additional detail will be provided, and an ongoing review of Power Forward implementation will occur, through work plans[32] and detailed financial projections that would be subject to intervenor scrutiny and Commission review as part of the annual Grid Rider proceeding. Incurred costs would be subject to a prudency review by the Commission, as would be forward-looking cost projections. Witness Simpson testified that the ten-year duration of Power Forward is preferred because a shorter duration would result in higher prices for labor and material, while a longer duration potentially would involve significant staff turnover, and thus increased training costs, in addition to a slower realization of benefits.

Witness Simpson disagreed with Public Staff witness Maness that Power Forward investments are customary spend that would be incurred regardless as part of DEC's continued obligation to maintain its infrastructure in order to provide reliable electric service to its customers. Witness Simpson contended that the costs referenced by witness Maness are maintenance-related costs, not the upgrades and improvements contemplated by Power Forward, which will "convert [DEC's] legacy grid to a next-generation grid that will support our digital society and enable emerging technologies that will benefit customers now and into the future." Tr. Vol. 23, p. 165.

[32] On April 2, 2018, DEC filed a late-filed exhibit containing such plans for 2018 and 2019 only.

In response to Public Staff witness Williamson's concern that Targeted Undergrounding, in particular, is not a novel or extraordinary investment, witness Simpson conceded:

> … that burying lines is by no means a novel technology; however, the data resolution and analytical tools that enable the Targeted Undergrounding program are novel—and necessary—to effectively and cost-efficiently know which lines to bury to reduce the maximum number of outages.

Id. at 165-66.

In response to Tech Customers witness Strunk's assertion that the Company has not sufficiently linked its proposed Targeted Undergrounding program to deficiencies in the existing grid, witness Simpson opined that Targeted Undergrounding "will decrease the number of [grid failure] events by as much as 30 to 40 percent." Id. at 177. He opined further that three Power Forward programs combined would improve SAIDI and SAIFI metrics by 40-60%. (Those three programs are Targeted Undergrounding, Hardening and Resiliency, and Self-Optimizing Grid.) Also in response to witness Strunk, witness Simpson testified that the distinction between customary T&D projects and Power Forward projects revolves around "the pace of the expenditures, not the classification of the investment." Id. at 169. Witness Simpson disputed that the Grid Rider would incentivize recovery of customary T&D costs through the Grid Rider, arguing that Power Forward "is comprised of a specific set of projects." Id. at 170. Witness Simpson conceded, however, that some of the projects described as Power Forward "do indeed have similar descriptions as customary [T&D] capital spending." Id. at 180.

In response to EDF witness Alvarez's concerns surrounding the costs of the Targeted Undergrounding program, witness Simpson testified that the per-customer cost referenced by witness Alvarez is inaccurate and that, in any case, the benefits of undergrounding are not limited only to those customers whose service is undergrounded. According to witness Simpson, undergrounding the outlier segments of the grid would eliminate over 50% of overhead system events and over 40% of all system events. Witness Simpson testified that for DEC, the Targeted Undergrounding program will result in an 18% improvement in SAIDI, a 17% improvement in SAIFI, a 36% reduction in non-major event day outages, and a 30% reduction in major event day outages.

In response to several intervenors' concerns that DEC has not sufficiently shown that the existing grid is unreliable enough to warrant the Power Forward spending and resulting rate increase, witness Simpson testified that "the directional trend is clear and consistent—both SAIDI and SAIFI are projected to [worsen] through the year 2026." Id. at 176.

In response to several intervenors' suggestions that a separate proceeding is needed to fully evaluate DEC's Power Forward initiative, witness Simpson disagreed because "[Power Forward] is no different from the grid planning the Company has [sic] done for years, but this initiative is more comprehensive in scope and period than is typical." Id. at 193. In addition, witness Simpson referenced the Technical Workshop that DEP was ordered to hold in early 2018. He again referred to the annual Grid Rider proceeding, which he said would be the avenue through which the Commission and intervening parties could evaluate DEC's Power Forward plans and expenditures.

In response to witness O'Donnell's testimony that DEC's customers are unlikely to see the value in a large rate increase to pay for Power Forward programs, witness Simpson pointed to research data purportedly showing that customers support the idea of grid improvement, even at a somewhat increased cost.[33] Witness Simpson stated that all ratepayers should see positive impacts from Power Forward programs, even after accounting for the increase in electric service rates, through either direct benefits like a reduction in power outages or through indirect benefits, like increased upward pressure on wages and increased economic activity.

In response to several intervenors' testimony contending that the Grid Rider, if allowed, would undermine the Commission's regulatory authority, witness McManeus testified that the Commission has allowed a number of cost-tracking riders, both as directed by the North Carolina General Assembly and in general rate cases, to recover capital and operating costs associated with various items. Although witness McManeus conceded that cost-tracking riders typically are used for regulatory compliance costs or volatile costs outside of the Company's control which comprise a significant component of operating expenses, she stated that riders are not necessarily limited to only these kinds of expenditures. She testified that the Grid Rider would be subject to an annual "mini-rate case" before the Commission, during which the following would allow for sufficient scrutiny of Power Forward costs: stakeholder participation, discovery, evidentiary hearing, true-up mechanism, review and audit of costs by the Public Staff, and expert witness testimony, along with the Company having to bear the burden of proving that the capital or O&M spend was reasonably and prudently incurred. In addition, witness McManeus testified that the Commission would retain authority over the Company's profitability through DEC's total electric earnings quarterly report filings and annual cost of service filings. For these reasons, witness McManeus contended that the costs associated with Power Forward actually would be subject to heightened Commission scrutiny if recovered through the Grid Rider, as opposed to a general rate case.

Witness McManeus specifically addressed intervenor concerns that the use of a rider would allow the Company to over-earn by creating an unbalanced regulatory process. Witness McManeus testified that the costs recovered through the rider would always be limited to actual costs incurred through the use of the EMF mechanism proposed in the Grid Rider. Any amounts over-collected from customers are refunded with interest. DEC witness Hevert also testified that an evaluation of the Company's peers, many of which he stated have rate mechanisms similar to the Grid Rider in place,

[33] The Commission notes that other information in this same exhibit seems to indicate that 79% of customers would not find grid modernization investments to be reasonable if they resulted in only a 3% rate increase.

is necessary to determine whether a Grid Rider would affect DEC's cost of equity or rate of return on equity.

Witness McManeus clarified that DEC does not intend to "have the proposed [Grid Rider] supplant the traditional cost based rate cost recovery process." Id. at 336. Rather, according to witness McManeus, DEC is seeking to avoid a 4- to 26-month delay in cost recovery for a high volume of large expenditures involving short construction periods. Witness McManeus stated further that:

> [i]f rate cases did not occur every year, then this lag in the timing of cost recovery is multiplied. In contrast, such lengthy delays have been avoidable for large generation investments, where rate cases are often timed around the estimated completion date of the single large investment.

Id. at 337. Witness McManeus explained that the Company intends to "reflect the financing costs during the construction period through the capitalization of AFUDC." Id. at 338. Only after completion of each project and placing it into service, clarified witness McManeus, would its costs be incorporated into the Grid Rider.

Commission Determinations

The Commission has thoroughly reviewed with care the evidence on the issues surrounding DEC's request for special ratemaking treatment of Power Forward costs; namely, to establish a Grid Rider, or, alternatively, to create a regulatory asset.

While no intervenor generally disagrees with the Company's stated goals of improving and modernizing the grid, the Public Staff and other intervenors unanimously oppose DEC's proposed cost recovery mechanism for these investments. Similarly, while the Commission does not disagree with DEC's stated goals of improving reliability and modernizing the grid, the Commission concludes that it is without statutory authority to allow DEC's request for special ratemaking treatment of Power Forward costs.

As an initial matter, the Commission notes that – with the exception of deployment costs of AMI meters, which DEC is not seeking to recover through the Grid Rider and which are addressed elsewhere in this Order – DEC is not seeking recovery in the instant rate case of Power Forward expenditures incurred during the test year. As such, it would be premature for the Commission to evaluate at this time the prudency or reasonableness of the Company's Power Forward investments. Existing dockets (such as Integrated Resource Planning and Smart Grid Technology Plans), as well as future general rate case proceedings, will provide opportunities for the Commission, at the appropriate time, to consider evidence to evaluate the prudency and reasonableness of Power Forward costs.

A. No exceptional circumstances exist to justify the Grid Rider

DEC in its post-hearing brief, among other things, argues that past cases in which the Commission has created a rider in general rate case proceedings are analogous to the establishment of the Grid Rider in this case, and, therefore, the Commission has the statutory authority to implement the Grid Rider. The Public Staff, AGO, NCSEA, Tech Customers, and other intervenors argue that many of the same cases labeled by DEC as analogous are, in fact, distinguishable, from the issues in the instant proceeding, and, therefore, the Commission does not have the statutory authority to implement the Grid Rider.

As a starting point, the Commission recognizes that certain statutory parameters exist around the authority delegated to it by the Legislature:

> North Carolina Statutes and case law contain explicit limits as to the procedures through which the Commission may revise the rates of a public utility. They are as follows: (1) a general rate case pursuant to G.S. 62-133; (2) a proceeding pursuant to a specific, limited statute, such as G.S. 62-133.2; (3) a complaint proceeding pursuant to G.S. 62-136(a) and G.S. 62-137; or (4) a rulemaking proceeding.

Order Denying Request to Implement Rate Rider and Scheduling Hearing, Docket No. E-7, Sub 849, at p. 18, n.2 (June 2, 2008) (citing State ex. rel. Utils. Comm'n v. Nantahala Power and Light Co., 326 N.C. 190, 195, 388 S.E.2d 118, 121 (1990)). In the instant proceeding – a general rate case pursuant to N.C. Gen. Stat. § 62-133 – the Commission clearly possesses the authority to establish a cost-tracking rider if exceptional circumstances existed to justify such action. Indeed, myriad precedent exists in which the Commission has done just that, even in the absence of an express enabling statute,[34] and the Supreme Court of North Carolina has upheld the Commission's authority to establish a cost-tracking rider when exceptional circumstances, such as a national fuel crisis causing a utility's gas costs to fluctuate unpredictably, warrant such action. See, e.g., State ex rel. Utils. Comm'n v. Edmisten, 291 N.C. 327, 230 S.E.2d 651 (1976) (Edmisten I); State ex rel. Utils. Comm'n v. Edmisten, 291 N.C. 451, 232 S.E.2d 184 (1977) (Edmisten II).

DEC in its post-hearing brief acknowledges that the Commission has in the past recognized the limitations on its authority to create cost-tracking riders in general rate cases; namely, that compelling circumstances must exist to justify special ratemaking

[34] See, e.g., Order Approving Partial Rate Increase and Allowing Integrity Management Rider, Docket No. G-9, Sub 631, at p. 39 (Dec. 17, 2013) (approving an Integrity Management Rider as part of a general rate case decision); Order Approving Partial Rate Increase and Requiring Conservation Initiative, Docket No. G-9, Sub 499 (Nov. 3, 2005) (approving a Customer Utilization Tracker as part of a general rate case decision); Order Granting General Rate Increase and Approving Amended Stipulation, Docket No. E-7, Sub 909 (Dec. 7, 2009) (approving a Coal Inventory Rider as part of a general rate case decision).

treatment.[35] In addressing said limitations, DEC attempts to argue that the magnitude of Power Forward investments, combined with the possibility that regulatory lag of cost recovery for such investments would be detrimental to the Company, are sufficiently exceptional circumstances to justify special ratemaking treatment in the instant proceeding. Accordingly, DEC attempts to argue that the facts in Edmisten I are analogous to DEC's proposed Grid Rider in the instant proceeding. The Commission is unpersuaded by this argument.

Edmisten I approved the use of a fuel adjustment rider in connection with a general rate case. There, the Court noted that the rider at issue "does indeed isolate for special treatment only one element of the utility's cost," but nonetheless approved the additive since it was adopted in connection with a general rate case and was of a nature that merely involved the application of a mathematical formula to the established rates going forward. Edmisten I, 291 N.C. at 340, 230 S.E.2d at 659. Notably distinguishable from the facts in the instant proceeding, however, Edmisten I (1) involved a rider that was adopted in the context of exigent circumstances related to the national fuel crisis in the 1970s, and only after the utility in that case demonstrated a clear connection between recovery of its fuel costs and its financial viability; (2) involved a rider that permitted recovery of core operating costs that now are recoverable under express statutory mechanisms; and (3) did not involve forecasted expenditures or evaluations, but rather permitted rate adjustments by application of a mathematical formula. In other words, the Commission established just and reasonable rates and then adopted a going-forward adjustment mechanism that it found necessary to achieve just and reasonable rates based on the exigencies of the energy crisis, which were beyond the utility's control, impacting the utility's expenditures. Crucially, the Supreme Court of North Carolina recognized in upholding the Commission's establishment of a fuel adjustment clause in Edmisten I that the "Commission, cognizant of its primary duty to fix just and reasonable rates, found upon uncontradicted evidence that the only way it could perform this duty under the facts was to permit use of the fuel clause." Id. at 346. Contrast such findings with those in the instant proceeding, in which the Commission finds and concludes that not only did DEC fail to show that the only way to achieve just and reasonable rates would be to allow special ratemaking treatment of Power Forward costs, but also that the greater weight of the evidence supports the conclusion that to allow the Grid Rider as requested would create unjust and unreasonable rates, in the Company's favor. Furthermore, the Commission finds that none of the facts justifying adoption of the fuel adjustment clause in Edmisten I are present in the instant proceeding. Where Edmisten I addressed fuel costs to be incurred by the utility as an essential component of its utility operations, DEC proposes in the instant proceeding to recover projected, future T&D expenditures for projects not yet identified, which are discretionary on its part. Where Edmisten I was decided in the context of wildly fluctuating fuel costs that threatened the utility's financial viability, here, DEC has complete control over the proposed spending, the rate of spending, and the timing of spending on Power Forward programs; it also has full control over its test year and the timing and frequency of when its applications for a general rate increase are filed. For these reasons, contrary to DEC's argument, Edmisten I cannot be

[35] See, Order Approving Partial Rate Increase, Docket No. G-5, Sub 356, at p. 11 (Sep. 25, 1996).

read to endorse an end-run around the statutory rate-setting mechanisms; to the contrary, central to the Court's holding in Edmisten I was the Commission's conclusion that the rider was critical to the achievement of the statutorily-prescribed rates.

NCSEA and Tech Customers argue in their post-hearing briefs that a case in which the Commission addressed whether a utility could recover the costs of replacing bare steel and cast-iron mains and services through a rider, when the collected funds would be used to pay for expansion facilities, is analogous to DEC's proposed Grid Rider. See In re Pub. Serv. Co. of N.C., Docket No. G-5, Sub 356, pp. 10-13 (Sep. 25, 1996) (PSNC). The Commission agrees. In PSNC, the Commission explained that its legal authority to authorize riders that have the effect of adjusting rates outside of general rate cases is limited to specific "circumstances involving highly variable and unpredictable expense or volume levels beyond the control of the utility." Id. The Commission rejected the proposed rider in PSNC as unlawful for a number of reasons. First, the Commission found that "the cost had not been shown to constitute an unpredictable portion of … annual construction expenditures" and that the utility "has control as to how much, how often and when the replacement takes place," meaning that the "expenditures are not highly variable or unpredictable, and they are generally controllable" by the utility. Id. Accordingly, the Commission held that implementation of the rider proposed in PSNC did not fall within its authority to establish. The Commission noted a number of other concerns, including the possibility that rates would become unreasonable because the rider "would permit PSNC to recover the cost of the replacement mains without recognition of associated decreases in expenses or increases in revenues," a concern that was magnified "by the sheer magnitude and pace of PSNC's replacement program." Id. The Commission further noted that the rider "would require present ratepayers to pay for certain capital improvements as the funds are expended, rather than as the service is provided," which would "cause current ratepayers to subsidize the cost of serving future generations of ratepayers." Id.

Similarly, as argued by NCSEA and Tech Customers, the Commission agrees that a request for an annually adjustable nonutility generator (NUG) rider is analogous to DEC's proposed Grid Rider. See Order Approving Partial Rate Increase, Docket No. E-22, Sub 314 (Feb. 14, 1991) (VEPCO). In VEPCO, NC Power sought approval to recover future NUG expenses that it was contracted to incur over seven years through a NUG rider, with both deferred accounting and true-ups. In rejecting this request, the Commission found that (1) an annual adjustment for purchases of this type outside of a general rate case was not authorized by statute; (2) there was insufficient justification for treating purchased power expenses any differently from any other expense items in the ratemaking process; and (3) that "the NUG rider mechanism would preclude appropriate regulatory oversight of the Company's overall expenses … because increases in payments to NUGs for additional capacity and energy could be offset by decreases in other cost of service items" that would not be accounted for without a general rate case. Id. at 19. Based on these "policy and legal concerns," the Commission denied NC Power's request.[36] Id. at 20.

[36] The Commission also noted that the fuel charge adjustment statute had been narrowly construed by the appellate courts, citing State ex rel. Utils. Comm'n v. Thornburg, 84 N.C. App. 482, 353 S.E.2d 413 (1987). There, the Court overturned the Commission's use of an "experience modification factor" to allow

DEC's proposed Grid Rider is analogous to the riders rejected by the Commission in PSNC and VEPCO, and is, accordingly, rejected for the same reasons. With the limited exception of federally-mandated reliability standards, DEC has complete control over the amount and timing of Power Forward expenditures, which thus are entirely predictable. DEC, through its request for the Grid Rider, merely seeks to recover more quickly costs that it has historically recovered without the need for a rider. Furthermore, there is no evidence in the record that without special ratemaking treatment for Power Forward costs, DEC would be unable to remain a strong, financially viable company.

The Commission finds and concludes that cost-tracking riders not specifically established by statute are and should continue to be considered an exception to the general ratemaking principles put in place by the General Assembly and this Commission.[37] In the instant case, there is no specific enabling statute or legislative directive requiring the establishment of the Grid Rider, and, therefore, it falls to the Commission to determine whether the circumstances presented by DEC are exceptional. The Commission finds and concludes that DEC has not presented exceptional or otherwise compelling circumstances to justify special ratemaking treatment of Power Forward costs.

DEC has raised concerns about the regulatory lag for its Power Forward investments. As an initial matter, the Commission notes that regulatory lag is not a new obstacle facing the utilities; rather, it always is present, to a certain extent, in an integrated, investor-owned utility market such as North Carolina. Although DEC in the instant proceeding testified from the perspective of the utility in characterizing regulatory lag as a problem necessitating a solution, it should be pointed out that regulatory lag in certain amounts can give company management an incentive to economize and make more worthwhile investments. Company witnesses Fountain and McManeus stated that while the Grid Rider would alleviate some regulatory lag, it would not be a significant reduction. DEC witness McManeus further stated that the Company did not do an analysis to determine the Company's cash flow with and without the rider; thus, there is no evidence in the record that the Company would be unable to carry out its operations without the requested cost-tracking rider. Therefore, the Commission finds DEC's regulatory lag concerns to be unpersuasive.

CP&L to recover a past under-recovery of fuel costs. Id., 84 N.C. App. at 490, 353 S.E.2d at 418. In light of the holding of the Court of Appeals, the Commission concluded "that an adjustment to base rates outside a general rate case, for which there is no specific statutory authority, to reflect a true-up of NUG expenses would be found unauthorized." Id. at 19.

[37] It should be noted, however, that there exists a plethora of precedent in which the Commission previously has approved the establishment of non-cost tracking riders in its adjudication of general rate cases, like the matter before the Commission in the instant proceeding. It also has approved the establishment of cost-tracking riders in its adjudication of general rate cases, when exceptional circumstances so warranted.

For all of these reasons, the Commission concludes that the Company's request for a Grid Rider should be denied. For the same reasons, the Commission concludes that the modified Grid Riders advanced by the Company in its post-hearing brief and Pilot Grid Rider Agreement and Stipulation, respectively, should also be denied.

B. Power Forward costs do not justify deferral accounting through a regulatory asset

Having already determined that DEC has failed to show that exceptional circumstances justify the establishment of a rider to recover Power Forward costs, the Commission now turns to DEC's request, in the alternative, to allow deferral accounting through the establishment of a regulatory asset for Power Forward costs.

As an initial matter, the Commission recognizes that it has in the past "historically treated deferral accounting as a tool to be allowed only as an exception to the general rule, and its use has been allowed sparingly." Order Approving Deferral Accounting with Conditions, Docket No. E-7, Sub 874, p. 24 (March 31, 2009). In addition, the Commission recognizes that it:

> has also been reluctant to allow deferral accounting because it, typically, equates to single-issue ratemaking for the period of deferral, contrary to the well-established, general ratemaking principle that all items of revenue and costs germane to the ratemaking and cost-recovery process should be examined in their totality in determining the appropriateness of the utility's existing rates and charges.

Id.

Turning now to the issues presented in the instant proceeding, the Commission finds and concludes that the reasons DEC says underlie the need for Power Forward are not unique or extraordinary to DEC, nor are they unique or extraordinary to North Carolina. Weather, customer disruption, physical and cyber security, DER, and aging assets are all issues the Company (and all utilities) have to confront in the normal course of providing electric service. The Commission further finds and concludes that while DEC intends to expend significant funds for T&D projects over the next ten years, a number of the Power Forward programs and projects proposed by DEC to be recovered through the Grid Rider are the kinds of activities in which the Company engages or should engage on a routine and continuous basis. Therefore, the Commission must conclude that Power Forward costs, as proposed in the instant proceeding, are not appropriate to be considered for deferral accounting. In reaching these conclusions, the Commission afforded substantial weight to the testimony of Public Staff witnesses Maness and Williamson, NCSEA witness Golin, and Tech Customers witness Strunk; conversely, the Commission was unpersuaded by DEC witness Simpson's contentions that Power Forward programs are new, novel, or extraordinary.

For example, monitoring, maintaining, and replacing aging equipment with like or new components, regardless of the pace at which these activities are conducted, is part of the Company's ongoing obligation to provide adequate and reliable electric service. In addition, the Commission concludes that new data analytics tools that DEC is using to identify the line segments in its Targeted Underground program do not make the program itself an extraordinary or unique modernization project. Undergrounding of lines is not a new concept, as conceded by DEC witness Simpson. Data analytics, as witness Simpson admitted, is neither a new phenomenon, nor is this current iteration of data analytics likely to remain unchanged for the foreseeable future.

Next, the Commission finds and concludes that the Distribution Hardening and Resiliency program contains, in its entirety, projects that also are within the scope of the Company's normal course of operating and maintaining the distribution grid. Of the categories of projects within this program, witness Simpson conceded that the transformer retrofitting, cable replacement, deteriorated conductor replacement/line rebuild, and pole hardening categories are also included in the Company's customary spend budget for the next five years. The Commission finds and concludes that these project categories are clearly within the Company's normal course of business and are not unique nor appropriate to be deferred.

Further, the Commission finds and concludes that the Transmission Improvements program also consists of projects that replace, rebuild, or improve existing transmission equipment. Federal reliability standards change as necessary to ensure national grid stability and reliability. DEC will be required to make the necessary improvements and modifications to its grid in order to remain compliant with such standards now and in the future, just as it has done for decades. Witness Simpson admitted that meeting such federal standards is customary as part of the Company's Business Expansion/Capacity expenditures. Therefore, these programs, too, are within the Company's ordinary course of business, and thus not appropriate for special ratemaking treatment.

Additionally, the Commission finds and concludes that DEC did not provide sufficient information to show how the Company will determine which Self-Optimizing Grid projects should be assigned to and recovered from the interconnection customers who would benefit the most from this capacity-enhancing and grid-strengthening work. Further, whether the majority of the money allocated to this program is for the replacement of lines deemed inadequate to handle new DERs on the system or new back feed or tie-in lines is unclear from the evidence presented. Either way, the Commission finds that back feed or tie-in lines do not represent new work or grid modernization, as witness Simpson testified. In fact, the addition of these kinds of lines is part of normal operations and the Company has added many of them to the grid in areas within its service territory in the past for purposes of ensuring reliable service to its customers.

Lastly, Enterprise Systems and Communications Network Upgrade programs include upgrades to several systems that the Company already uses to enable data acquisition and analytics to help control the grid. The Commission finds, therefore, that these upgrades are no different than many upgrades to other systems that the Company has made in the past and currently is in the process of making. One example is the Customer Connect program, which is an update to the existing customer information system and not included in Power Forward. The Commission considers these upgrades to constitute part of the ordinary evolution of the Company's business.

For all of these reasons, the Commission finds and concludes that DEC has not satisfied the criteria for deferral accounting treatment of Power Forward costs. In order for the Commission to grant a request for deferral accounting treatment, the utility first must show that the cost items at issue are adequately extraordinary, in both type of expenditure and in magnitude, to be considered for deferral. Second, the utility has to show that the effect of not deferring such cost items would significantly affect the utility's earned returns on common equity. Although it was uncontested by any party that DEC's planned Power Forward spend is extraordinary in magnitude, the Commission is unpersuaded that the entirety of Power Forward programs as proposed are unique or extraordinary. Assuming arguendo that all Power Forward programs as proposed were found to be unique and extraordinary, thus meeting the threshold criteria for consideration of deferral accounting, DEC failed to show that the effect of not deferring Power Forward costs would significantly affect its earned returns on common equity.

The Commission appreciates the Company's undertaking to strengthen and modernize its grid and retool other systems, and encourages its efforts. The Commission recognizes that the costs the Company has identified are substantial and that, by and large, the individual projects are of insufficient length to qualify for CWIP or AFUDC before such projects can be completed and placed in service. Without a rider or an order deferring costs, the Company risks an erosion of earnings from regulatory lag. Likewise, these circumstances promote more frequent, costly rate cases.

Nevertheless, the Commission determines as addressed herein that it does not possess the authority to approve the Grid Rider and that the description of projected projects on this record is insufficient to properly categorize customary spend projects, which the Company must undertake to comply with its franchise obligations, from extraordinary Power Forward or grid modernization projects.

With respect to deferral, the Commission acknowledges that, irrespective of its determination not to defer specific costs in this case, the Company may seek deferral at a later time outside of the general rate case test year context to preserve the Company's opportunity to recover costs, to the extent not incurred during a test period. In that regard, were the Company in the future before filing its next rate case to request a deferral outside a test year and meet the test of economic harm, the Commission is willing to entertain a requested deferral for Power Forward, as opposed to customary spend, costs. Should a collaborative undertaking with stakeholders as addressed herein produce a list of Power Forward projects, such designation would greatly assist the Commission in addressing a requested deferral. Were the Company to demonstrate that the costs can be properly classified as Power Forward and grid modernization, the Commission would seek to expeditiously address the request and to determine that the Company would meet the "extraordinary expenditure" test and conceptually authorize deferral for subsequent consideration for recovery in a general rate case.

The Commission can authorize a test for approving a deferral within a general rate case with parameters different from those to be applied in other contexts. Consequently, with respect to demonstrated Power Forward costs incurred by DEC prior to the test year in its next case, the Commission authorizes expedited consideration, and to the extent permissible, reliance on leniency in imposing the "extraordinary expenditure" test.

Having concluded that the Grid Rider and the Company's alternative request to allow deferral accounting of Power Forward costs should be denied, the Commission need not address the related issues, which also were contested by the intervenors, of cost allocation and rate design of the Grid Rider. DEC should seek recovery of its Power Forward expenditures through the traditional general ratemaking process outlined in N.C. Gen. Stat. § 62-133.

C. <u>DEC shall utilize existing Commission dockets to collaborate with stakeholders</u>

The Commission finds and concludes that several of the intervening parties have raised valid concerns regarding the need for additional transparency and detailed information regarding Power Forward. Although the Commission concluded in this proceeding that Power Forward costs do not warrant special ratemaking treatment, the Commission finds and concludes that additional information would be helpful to the Commission, the Public Staff, and to other intervening and interested parties to better understand Power Forward projects, grid modernization in general, and the cost-effectiveness of such programs.

EDF and NCSEA, in their post-hearing briefs, make compelling arguments that the Commission will not repeat here in support of their position that the Commission should establish a separate, generic docket for the purpose of investigating and evaluating the grid modernization plans of all investor-owned utilities in North Carolina. In addition, the Commission notes that EDF provides a comprehensive overview of grid modernization issues and proceedings, as handled in a number of other jurisdictions. Similarly, the Public Staff requests that DEC be required to include in its Smart Grid Technology Plan filings, required by Commission Rule R8-60.1, more detailed information on Power Forward investments.

While the Commission declines to adopt in its entirety either recommendation advanced by the intervening parties with respect to a separate proceeding to further evaluate some of the issues surrounding Power Forward and grid modernization, the Commission recognizes that there could be value in further collaboration between DEC and the intervening parties on how to resolve these issues, which the Commission expects will continue to be raised until such time as the parties can find a solution within our existing statutory framework. With that said, the Commission directs DEC to utilize an existing proceeding, such as the Integrated Resource Planning and Smart Grid Technology Plan docket, to inform the Commission, and to engage and collaborate with stakeholders to address the myriad of issues raised in the context of Power Forward and the Company's proposed Grid Rider.

D. The Pilot Grid Rider Agreement and Stipulation is disapproved

DEC, EDF, the Sierra Club, and NCSEA (Grid Rider Stipulating Parties) contend that their jointly-filed Pilot Grid Rider Agreement and Stipulation Among Certain Parties (Grid Rider Agreement), the contents of which the Commission will not in this Order summarize in detail, addresses several of the concerns raised by the parties regarding Power Forward and the Grid Rider. The Grid Rider Stipulating Parties further contend that a number of concessions were made both by DEC and its counterparties in order to reach the consensus that culminated with the filing of the Grid Rider Agreement. In essence, the Grid Rider Agreement contains a revised Power Forward proposal on a smaller scale, with a shorter duration and limitations on the Company's spending, at least during the initial three-year pilot period. The Grid Rider Agreement represents a hybrid of the Company's initial cost recovery and alternate cost recovery requests, with most costs being recovered through the Grid Rider during the first three years, followed by deferral of such costs thereafter.

While the Commission appreciates the efforts to resolve some of the contested issues surrounding Power Forward and the Grid Rider, the Commission nevertheless concludes that the Grid Rider Agreement must be disapproved. As an initial matter, even if the Commission hypothetically were to find that the Grid Rider Agreement sufficiently mitigates the valid concerns about Power Forward and the Grid Rider as expressed by the intervening parties throughout this proceeding, the Commission nonetheless still would be required to reach the same conclusion that the law as it currently exists does not allow for the establishment of a rider to recover costs that are predictable and within the utility's control.

In addition to the issue of legality, which in and of itself precludes under the instant circumstances the Commission's consideration of the Grid Rider Agreement, the Commission agrees with NCJC et al. and NC WARN that it would constitute poor policy to allow a partial group of interested parties to develop plans for grid modernization through settlement negotiations that address only certain of a number of contested issues, particularly when the Grid Rider Agreement was filed after the close of the evidentiary record in this proceeding, thus precluding entirely the opportunity for cross examination.

In conclusion, the Commission finds and concludes that the Grid Rider Agreement should be disapproved, for many reasons including the rationale for denying the Company's requests for special ratemaking treatment of Power Forward costs in the first place.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 45-49

The evidence supporting these findings of fact and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of Company witnesses Fallon, Diaz, and McManeus, CUCA witness O'Donnell, Tech Customers witness Kee, and Public Staff witnesses Metz, Maness, and Boswell, and the entire record in this proceeding.

In Docket No. E-7, Sub 819, which has been consolidated with this general rate case, the Company requests Commission approval of its decision to cancel the Lee Nuclear Project pursuant to N.C. Gen. Stat. § 62-110.7(d). In this general rate case, the Company requests permission to move the adjusted balance of the Lee Nuclear Project development costs from CWIP Account 107 to regulatory asset Account 182.2 and to recover the project development costs in rates by amortizing such costs over a 12-year period. The Company also requests that the unamortized balance of such costs be included in rate base to recover a net-of-tax return on the unamortized balance.

DEC witness Fallon testified that in its 2005 and 2006 Integrated Resource Plans (IRPs), the Company identified the need for significant capacity additions by summer 2016 and found nuclear generation to be a least cost supply-side alternative. Tr. Vol. 10, p. 182. In March 2006, DEC announced that it had selected the site for Lee in Cherokee County, South Carolina, to evaluate for possible nuclear expansion. Tr. Vol. 10, p. 183. On September 20, 2006, the Company filed a request in Sub 819 for a declaratory ruling for authority to recover the North Carolina allocable portion of necessary costs and obligations to be incurred through December 31, 2007. On March 20, 2007, the Commission issued its Order Issuing Declaratory Ruling (2007 Order), in which the Commission determined that it was appropriate for DEC to pursue project development work up to $125 million through December 31, 2007, for the Lee Nuclear Project and that DEC could recover the project costs in the manner determined to be appropriate by the Commission and allowed by law.

On January 1, 2008, N.C. Gen. Stat. § 62-110.7 went into effect. This statute provides for Commission review of a utility's decision to incur nuclear project development costs. Under this statute, prior to filing an application for a Certificate of Public Convenience and Necessity (CPCN) in North Carolina or another state, a public utility may request that the Commission review its decision to incur nuclear project development costs. Under N.C. Gen. Stat. § 62-110.7(a), project development costs are defined as:

> all capital costs associated with a potential nuclear electric generating facility incurred before (i) issuance of a certificate under G.S. 62-110.1 for a facility located in North Carolina or (ii) issuance of a certificate by the host state for an out-of-state facility to serve North Carolina retail customers, including, without limitation, the costs of evaluation, design, engineering, environmental analysis and permitting, early site permitting, combined operating license permitting, initial site preparation costs, and allowance for funds used during construction associated with such costs.

Generally speaking, under N.C. Gen. Stat. § 62-110.7(b), the Commission shall approve a utility's decision to incur project development costs if the utility demonstrates that the decision to incur such costs is reasonable and prudent; however, the Commission does not consider the reasonableness or prudence of any specific activities or items of costs until a rate case proceeding. North Carolina Gen. Stat. § 62-110.7(c) provides that reasonable and prudent project development costs shall be included in the utility's rate base and be fully recoverable through rates in a general rate case. However, if the project is cancelled, as has occurred in this case, N.C. Gen. Stat. § 62-110.7(d) allows the utility to recover all reasonable and prudently incurred project development costs in a rate case amortized over the longer of five years or the period during which the costs were incurred, which in this case is 12 years. It should be noted that while N.C. Gen. Stat. § 62-110.7(c) provides for rate base treatment of project development costs and therefore includes a return, N.C. Gen. Stat. § 62-110.7(d), applicable to cancelled projects, only requires amortization of the costs and does not mention, and certainly does not mandate, a return.[38]

Witness Fallon testified that on December 7, 2007, DEC filed an Application for Approval of Decision to Incur Continued Generation Project Development Costs. Tr. Vol. 10, p. 186. Specifically, DEC sought approval of its decision to incur the North Carolina allocable share of an additional $160 million of Lee Nuclear Project development costs during 2008 and 2009 to maintain the ability to begin nuclear construction to serve customers in the 2018 timeframe as identified in the Company's 2007 IRP. Tr. Vol. 10, p. 187. The Commission approved DEC's request on June 11, 2008 (2008 Order). Tr. Vol. 10, p. 188.

On November 15, 2010, DEC filed an Amended Application for Approval of Decision to Incur Nuclear Generation Project Development Costs seeking approval to incur an additional $229 million of project development costs (later revised to $287 million), for a total of $459 million (including AFUDC) for the period January 1, 2010 through December 31, 2013, to allow Lee Nuclear to remain an option to serve customers in the 2021 timeframe. Tr. Vol. 10, pp. 188-89. The Commission did not approve DEC's request as filed, but in its Order dated August 5, 2011 (2011 Order), the Commission ruled that the nuclear project development costs incurred on or after January 1, 2011, would be subject to a not-to-exceed cap of the North Carolina allocable portion of $120 million and that its approval granted was limited to those nuclear project development costs that must be incurred to maintain the status quo with respect to the Lee Nuclear Project, including DEC's application for a combined operating license (COL) at the Nuclear Regulatory Commission (NRC). Tr. Vol. 10, pp. 190-91. As in the 2008 Order, the Commission allowed DEC to continue provisionally accruing AFUDC, stated that the Company would need to request regulatory asset treatment for any abandoned project development, and required DEC to continue filing semi-annual reports detailing activities and expenditures. Tr. Vol. 10 p. 191. The Commission did not retroactively approve the decision to incur project development costs during 2010. DEC did not seek further project development cost approval orders after the 2011 Order.

DEC witness Fallon testified that the Company incurred costs for the development of the Lee Nuclear Project of approximately $542 million through June 30, 2017. The

[38] The return at issue here is the return associated with the unamortized balance of a plant that has been abandoned, the costs of which, if not deferred for potential rate recovery through amortization, would otherwise be written off as of the date of abandonment as a loss on the income statement. It is not the return normally accrued on a plant's cost balance during construction, the allowance for funds used during construction (AFUDC), which is included in the definition of "project development costs" set forth in N.C. Gen. Stat. § 62-110.7(a).

costs are composed of the following categories: Combined Operating License Application (COLA) Preparation, NRC Review and Hearing Fees, Pre-Construction and Site Preparation, Land and Right of Way Purchases, Supply Chain, Construction Planning and Engineering, Operational Planning, Post COL, and AFUDC ($232 million of the $542 million), as reported in DEC's semi-annual reports to the Commission. Tr. Vol. 10, p. 178; Tr. Vol. 11 p. 19. He stated that in order to "maintain the status quo", DEC exceeded the cap set in the 2011 Order in 2013. Tr. Vol. 10, p. 192. Specifically, witness Fallon indicated that DEC began limiting its activities to only those activities and costs necessary to preserve the option of bringing the plant online around the 2021 target date, did not order equipment, and wound down non-essential site specific work and construction planning activities. Tr. Vol. 10, p. 208. He noted that the Company continued to substantially complete the design of the commercial buildings so that they could be completed in time to meet the 2021 date identified in the IRP. Id. According to witness Fallon, the Company completed its contractual commitments in areas no longer necessary to maintain the status quo and narrowed the scope of work to reduce costs. Further, he indicated that the Company wound down contracts so to preserve the work to be efficiently resumed at a later date. Id.

Witness Fallon also noted that the Company submitted a COLA with the NRC for two Westinghouse AP1000 Pressurized Water Reactors on December 13, 2007. Tr. Vol. 10 p. 180. He noted that a number of factors, many outside the control of DEC, led to a longer licensing period than originally anticipated. Tr. Vol. 10, p. 192. Witness Fallon stated that on December 19, 2016, the NRC issued a COL for the Lee Nuclear Plant allowing DEC to construct the units and to operate them for 40 years. Id. The licenses are renewable for an initial 20-year period and possibly a second 20-year period. Tr. Vol. 10, p. 181. Witness Fallon stated that under the terms of the COL, DEC is not compelled to build and operate the nuclear plant. Id.

Witness Fallon noted that the IRPs between 2006 and 2016 identified Lee Nuclear as a cost effective option to meet the need for base load, but the date of the earliest need for each unit moved to 2026 and 2028 in the 2016 IRP. Tr. Vol. 10, p. 185. He pointed out that through the 2016 IRP, Lee Nuclear Project continued to be least-cost carbon free generation option for customers. Tr. Vol. 10, p. 193. In addition, witness Fallon noted that having the COL for the Lee Nuclear Project would reduce the lead time required to license new nuclear plant at the site. Id. Witness Fallon also indicated that in DEC's latest IRP, the first Lee Nuclear unit would be needed no earlier than 2031, and then only in a carbon-constrained scenario with the assumption of no existing nuclear relicensing. Tr. Vol. 24, pp. 61-62.

In regard to the request to cancel the Lee Nuclear Project, witness Fallon said that since issuance of the COL, the risks and uncertainties in regard to beginning construction have become so great that cancellation was in the best interest of customers. Tr. Vol. 10, p. 195. He noted that in early 2017, Westinghouse announced its plans to exit the nuclear plant construction business, and then, on March 29, 2017, announced its bankruptcy. Tr. Vol. 10, p. 196. Additionally, the first two plants being constructed with AP1000 reactors, in South Carolina (V.C. Summer Project) and Georgia (Vogtle Project), have cost billions of dollars more than originally estimated and have faced significant delays. Id. Witness Fallon stated that the Westinghouse bankruptcy and the decision to stop construction at the V.C. Summer Project led to great uncertainty about the cost, schedule, and execution of construction for future nuclear projects, directly impacting the Lee Nuclear Project. Tr. Vol. 10, p. 198. Therefore, due to these uncertainties and risks, as well as projected low natural gas prices and uncertainty about carbon emission costs, witness Fallon testified that the Company thought that it is not in customers' best interest to construct and operate Lee Nuclear before the end of the next decade. Id. As a result, the Company requests to cancel the project, but maintain the COL. Tr. Vol. 10, pp. 198-99. Witness Fallon indicated that there would be post-COL costs of approximately $700,000 per year so the Company could make annual filings with the NRC and maintain the property. Tr. Vol. 11, p. 72.

DEC witness Diaz testified that in his experience as an NRC Commissioner, including serving as Chairman, he was thoroughly familiar with the AP1000 design and with the NRC licensing process. Tr. Vol. 10, p. 221. In reviewing DEC's decision to pursue the preparation of a COLA in 2005 and submit it to the NRC on December 13, 2007, witness Diaz stated DEC had chosen the optimal path to pursue licensing by using the NRC's new nuclear reactor licensing protocol pursuant to 10 C.F.R. Part 52 Rule (Part 52) (Tr. Vol. 10, p. 223), but that significant time was necessary due to Part 52 being untested. Tr. Vol. 10, p. 233. He noted that when DEC submitted its COLA, the NRC schedule provided for a 42-month period between submission of the application and receipt of the COL, though there was an expectation of a longer period due to the number of applications. Id.

Witness Diaz explained that the process to license the Lee Nuclear Project was delayed for a number of reasons outside of DEC's control, including delays related to the NRC's review of the Yucca Mountain licensing application (Tr. Vol. 10, pp. 235-36), the Waste Confidence Rule (Tr. Vol. 10, pp. 236-37), the Fukushima Dai-ichi accident (Tr. Vol. 10, pp. 238-39.), and the new Seismic Source Characterization. Tr. Vol. 10, p. 240. Additionally, delays occurred as DEC updated its COLA from Rev 16 to Rev 19 of the AP1000 (Tr. Vol. 10, pp. 241-42), changed the location of the reactor based on it improving reactor building stability and being more economical to construct (Tr. Vol. 10, pp. 242-43), added a make-up pond for cooling water due to the limited water in the main cooling source (Tr. Vol. 10, pp. 243-44), and amended the COLA to revise the cooling tower design. Tr. Vol. 10, p. 244. Witness Diaz testified that he believed that DEC acted prudently in making each of these changes and thus the resulting delays were reasonable. Tr. Vol. 10, pp. 241-44. He also noted difficulties associated with using Part 52 licensing that slowed the process, including requests for additional information (RAIs) and generic design issues, as well as design errors in Rev 19, all of which witness Diaz concluded DEC had managed in a reasonable and prudent manner. Tr. Vol. 10, pp. 245-48.

Witness Diaz also reviewed the cost breakdown for the COL and project-related costs for the Lee Nuclear Project and found that they compared favorably to the costs incurred by Florida Power & Light (FP&L) for its Turkey Point Units 6 and 7 COL. Tr. Vol. 10, p. 249. He discussed the disadvantages that would have resulted if DEC had suspended its efforts to license Lee Nuclear, the value of the Lee Nuclear COL, the advantages of DEC's licensing-first approach, and the reasonableness of the selection of the AP1000 design. Tr. Vol. 10, pp. 250-51. Witness Diaz concluded that based on his experience, DEC's approach to licensing and managing the Lee Nuclear Project, and its decision to extend the targeted operation dates, were reasonable and consistent with best practices. Tr. Vol. 10, p. 253. He further determined that the project costs incurred were reasonable and prudent. Tr. Vol. 10, p. 234.

DEC witness McManeus testified that the Company proposed amortizing the accumulated construction work in progress (CWIP) balance related to the Lee Nuclear Project. Tr. Vol. 6, p. 257. In her direct testimony, witness McManeus stated that the adjusted CWIP balance reflecting the actual costs incurred through June 30, 2017 and incorporating estimated additional expenditures through March 31, 2018, was $353.2 million and $527.1 million on a North Carolina and system basis, respectively. Id. She noted that non-depreciable land and its associated AFUDC had been removed from the balance. Id. This results in an annual revenue requirement of $52.6 million, consisting of an annual amortization expense over 12 years of $29.5 million, and a net of tax return on the unamortized balance of $23.1 million. Id.

CUCA witness O'Donnell testified that DEC's exceedance of the cap set in the 2011 Order without coming to the Commission for approval of its decision to incur further project development costs was an example of DEC's tendency to "beg forgiveness than to ask permission." Tr. Vol. 18, p. 51.

Tech Customers witness Kee testified regarding the Lee Nuclear Project. Tr. Vol. 18, pp. 164-65. Witness Kee addressed various issues surrounding whether DEC should recover costs incurred to develop the Lee Nuclear Project. Id. at 165-66. Witness Kee recommended that (1) DEC should only recover those costs incurred up to December 31, 2009, if those costs were within the amounts preauthorized by the Commission; (2) DEC should not recover any costs incurred during 2010; and (3) the Commission should completely disallow or significantly limit any recovery of costs incurred between January 1, 2011 and June 2017. Id. at 204-05.

As an alternative to completely disallowing cost after January 1, 2011, witness Kee divided the Lee Nuclear Project costs into two categories: Type 1 and Type 2. Id. at 181. Type 1 costs are "related to the NRC review of the Lee COL application." Id. Type 2 activities are "at most, indirectly related to the NRC COL review process, but were undertaken in preparation for the eventual construction and operation of the Lee nuclear project." Id. at 182. Witness Kee posited that Type 1 activities fall within the meaning of "maintain the status quo" under the 2011 PDO, and Type 2 activities represent expenditures beyond the status quo. Id. at 181. His alternative recommendation was to allow only those costs after January 1, 2011 that relate to Type 1 activities and are less than the amount approved in the 2011 PDO. Id. at 205.

Public Staff witness Metz testified regarding the Company's request for cancellation of the Lee Nuclear project and recovery of the project development costs.

He noted that the Public Staff hired as a consultant, Global Energy & Water Consulting, LLC, a firm with extensive experience with nuclear construction activities and NRC application processes, to (1) review the details of all costs charged to all the capital accounts assigned to engineering, licensing, and regulatory compliance for the Lee Nuclear Project; (2) review the decisions to begin, continue, and cancel the project, as well as issues with the AP1000 design, Westinghouse, and Westinghouse's owner, the Toshiba Corporation; (3) review DEC's project planning decisions; (4) compare the costs incurred to those of other utilities; and (5) identify any costs that were not reasonably or prudently incurred. Tr. Vol. 23, pp. 31-32. The Public Staff also reviewed the activities and costs internally. Tr. Vol. 23, p. 32. Based on the Public Staff's review as assisted by the consultants, the Public Staff found that with one exception involving design costs for a visitors' center, the costs incurred (not including AFUDC, which was reviewed by Public Staff witness Maness) were reasonably and prudently incurred based on information known at the time. Tr. Vol. 23, pp. 32-33. Witness Metz recommended that costs incurred for the architectural and engineering design of a visitors' center be disallowed on the basis that under the dictates of the 2011 Order, the costs did not directly support the COLA process at the NRC and were not necessary to maintain the status quo at that time. Tr. Vol. 23, pp. 33-34. This recommendation results in a disallowance of $507,009 on a system basis, exclusive of AFUDC. Tr. Vol. 23, p. 36.

Public Staff witness Maness testified that on behalf of the Public Staff, he investigated the reasonableness of the accrual of the AFUDC costs included in DEC's project development costs, and particularly DEC's dates for beginning and ending the accrual of AFUDC. Tr. Vol. 22, p. 100. Based on his review, witness Maness found the date on which DEC began accruing AFUDC to be reasonable, but recommended that AFUDC accrual end as of December 31, 2017, instead of the May 1, 2018, date estimated by DEC. Id. He testified that under FERC Accounting Release No. 5, AFUDC accruals must cease if construction is suspended or interrupted. Tr. Vol. 22, p. 101. Based on discussions between DEC and the Public Staff, witness Maness stated that the Company had confirmed that work on the Lee Nuclear Project had ended as of December 31, 2017, and that the Company had ceased accruing AFUDC at that time. Tr. Vol. 22, p. 102. He noted that removal of the estimated 2018 AFUDC from the costs proposed for Lee Nuclear recovery resulted in a $9 million adjustment. Id.

Public Staff witness Boswell contended that the Commission should adhere to its longstanding position that no adjustment should be allowed which would effectively enable the Company to earn a return on the unamortized balance of the construction costs of a nuclear plant that had been abandoned. Tr. Vol. 26, p. 140. She argued that the Commission has found in past cases that this treatment fairly allocated the loss between the utility and customers, and that customers should not bear all the risk of the cancelled plant. Id.

In his rebuttal testimony, witness Diaz disagreed with witness Kee's stratification of costs into two categories on the basis that both types of costs were necessary for the Company to adhere to the 2011 Order and to have the Lee Nuclear option available to meet the dates for need projected in DEC's IRPs. Tr. Vol. 26 p. 181. He noted that DEC could not have obtained the COL without exceeding the limits in the 2011 Order. Tr. Vol. 26, p. 182. Witness Diaz further testified about the value of the COL obtained by DEC. Tr. Vol. 26, pp. 186-88.

In rebuttal, Company witness Fallon testified that the Company did not oppose the recommendation of witness Maness to end the accrual of AFUDC for Lee Nuclear at December 31, 2017. Tr. Vol. 24, pp. 32, 33. In regard to witness Metz's proposed disallowance for the costs associated with the architectural and engineering of a visitors' center, witness Fallon explained the reasons why DEC sought to construct a visitors' center as one of the buildings with early design work, but conceded that witness Metz's conclusion to recommend a disallowance for these costs was reasonable. Tr. Vol. 24, p. 34.

Witness Fallon opposed the recommendation of Public Staff witness Boswell that DEC should not receive a return on the unamortized balance of the Lee Nuclear costs and associated accumulated deferred income taxes (ADIT). He noted that while witness Boswell referred to the costs of Lee Nuclear as having been prudently incurred, the financing costs of the unamortized balance were also prudently incurred costs. Tr. Vol. 24, pp. 34-35. Witness Fallon pointed out that N.C. Gen. Stat. § 62-110.7 does not prohibit DEC from receiving a return on the unamortized balance of prudently incurred costs. Tr. Vol. 24, p. 36. He argued that witness Boswell had not considered the specific facts of this case in making her recommendation of no return, including the fact that the Company had obtained a COL, the highly dynamic energy future, the advantages of maintaining fuel diversity, and the uncertainty of nuclear relicensing. Tr. Vol. 24, pp. 37-39. Witness Fallon also detailed the steps the Company took to mitigate the risks of the project. Tr. Vol. 24, p. 39.

In regard to the testimony of Tech Customers witness Kee, witness Fallon disagrees with the contention that all nuclear development costs must be approved or authorized in advance under N.C. Gen. Stat. § 62-110.7 to be recoverable. Tr. Vol. 24, p. 40. Witness Fallon noted that while the project development orders (PDOs) issued in Sub 819 have specific authorizations, they do not foreclose the possibility that DEC may recover costs outside of the strictures of those Orders. Tr. Vol. 24, p. 41. He also stated that utilities are permitted, but not required, to seek approval of the decision to incur project development costs under N.C. Gen. Stat. § 62-110.7, and that the Commission did not approve DEC's request for approval to incur Lee Nuclear costs in 2010, but it made no finding as to their recoverability. Id. Witness Fallon testified that DEC had exceeded the spending cap set in the 2011 Order. However, he testified that DEC interpreted the 2011 Order as requiring the Company to limit its spending to amounts necessary to preserve the option of building Lee Nuclear so that it would be available to meet the target dates of need set out in DEC's IRPs, including maintaining an active COLA at the NRC. Tr. Vol. 24, p. 44. In order to maintain this active COLA status, witness Fallon explained that DEC had to continue its permitting, pre-construction, engineering, design, construction planning, and operational planning activities to maintain the status quo. Tr. Vol. 24, p. 45. Further, witness Fallon testified that it was necessary for DEC to continue its efforts in many areas to avoid signaling to the NRC that DEC was not actively pursuing the Lee COL, which could have resulted in termination of the review process by the NRC prior to the issuance of the COL. Id.

On cross-examination, witness Fallon identified Tech Customers Fallon Rebuttal Exhibit 1 as an internal presentation made in February 2012 to the Company CEO's staff by himself and the nuclear development staff regarding the future of the Lee Nuclear Project. Tr. Vol. 24, p. 54. The exhibit showed the projected dollars spent that exceeded the limits of PDOs issued by the NCUC and the South Carolina Public Service Commission. Tr. Vol. 24, p. 56. The presentation indicated that filing for a subsequent PDO would put the NCUC in a "difficult position" as James E. Rogers, the CEO during the 2011 proceeding had testified that DEC would not proceed with Lee Nuclear unless the North Carolina General Assembly had enacted legislation allowing DEC to receive CWIP costs through a specified cost recovery process.[39] Tr. Vol. 24, p. 57. The presentation also noted the negative impact on the Lee Nuclear business case of projected low natural gas prices. Id. The presentation also pointed out the negative effect on the Lee Nuclear project that would result from a rejection of a further request for approval to incur nuclear development costs. Tr. Vol. 24, p. 58. Based on these factors, Nuclear Development recommended in 2012 that the Company not seek an additional PDO. Id. The Company also had another internal meeting in early 2013 where it again decided against pursuing a further PDO for similar reasons, as well as delays occurring with the NRC process. Tr. Vol. 24, pp. 62-64. Following the merger of Duke Energy Corporation and Progress Energy, Inc., a third senior management meeting was held in November 2013 to consider whether to pursue a PDO. Tr. Vol. 24, pp. 65-66.

Witness Fallon agreed that one of the purposes of N.C. Gen. Stat. § 62-110.7 is to help alleviate some portion of the risk that certain costs incurred for nuclear project development activities may be found to be imprudent. Tr. Vol. 24, p. 71. Witness Fallon stated that he was the Company witness supporting DEP's request in its recent rate case to recover COLA costs of approximately $45.3 million for its cancelled Harris Nuclear project. Tr. Vol. 24, p. 74. In that case, DEP did not seek a return on the unamortized balance of the costs for the COLA for the cancelled Harris Nuclear project. Tr. Vol. 24, p. 75. However, witness Fallon argued that the Harris Nuclear and Lee Nuclear projects are different because DEC had sought approval for the Lee Nuclear Project under N.C. Gen. Stat. § 62-110.7, the Lee Nuclear project had progressed beyond the development stage to receipt of a COL, and that the investor risk differed due to the amount of spending and the scope of activities. Tr. Vol. 24, pp. 75-77. Finally, witness Fallon acknowledged that while having the COL means that DEC may use its option to build the Lee Nuclear plant when the time is right, the time may never be right. Tr. Vol. 24, p. 82.

In her rebuttal testimony, Company witness McManeus noted that the Company did not oppose the recommendations of Public Staff witness Metz to remove certain costs associated with the design of a visitors' center from the Lee Nuclear costs or Public Staff witness Maness to remove AFUDC for the months after December 2017. Tr. Vol. 26,

[39] This testimony by Mr. Rogers was one of the factors cited by the Commission in its decision to issue only a limited approval of DEC's decision to incur project development costs in the 2011 Order.

p. 310. She testified that the Company did oppose the adjustment recommended by Public Staff witness Boswell to remove the unamortized balance of deferred project development costs and the associated ADIT from rate base, thereby preventing the Company from earning a return on the unamortized balance. Id. Witness McManeus argued that the Commission should consider that the Lee Nuclear project costs were financed by investors and should appropriately be in rate base. Tr. Vol. 6, p. 311. According to witness McManeus, if the Commission determines that the Lee Nuclear costs were incurred prudently, it should include those costs in rate base, thereby allowing the Company to earn a return on the unamortized balance. Id. On cross-examination, witness McManeus agreed that the decision to allow the Company to earn a return on cancelled plant was within the Commission's discretion. Tr. Vol. 8, p. 232. She further agreed that once the amortization of Lee Nuclear was completed, it would be inappropriate for the Company to re-establish the asset and thus recover it from the customers again. Tr. Vol. 26, p. 110. She indicated that if recovery of Lee Nuclear costs were allowed, DEC would have a regulatory asset that would be amortized over the period allowed, and then in DEC's next rate case, the balance of the regulatory asset would be addressed. Id.

Discussion and Conclusions on Lee Nuclear

A. Recovery of Costs

In regard to specific items of cost, the Commission agrees with Public Staff witness Metz that costs incurred for the architectural and engineering design of a visitors' center did not directly support the COLA process at the NRC and were not necessary to maintain the status quo at that time as directed by the 2011 Order. As such, these costs should be disallowed. The Commission also agrees with Public Staff witness Maness that accrual of AFUDC on the project should have stopped after all substantive work on the project had come to an end by December 31, 2017. As noted above, DEC did not contest either of these two proposed adjustments.

As noted above, Tech Customers witness Kee recommended disallowance of the costs incurred in 2010 and the costs in excess of the limit set in the 2011 Order. In its proposed order, Tech Customers supports this position. NC WARN supports the recommendations of witness Kee in its brief. In its proposed order, the AGO argues that given the evidence challenging the reasonableness and prudence of DEC's expenditures on and after January 1, 2011, and DEC's failure to provide details sufficient to identify what it would have cost to maintain the status quo, the costs incurred on or after January 1, 2011 for new development activities should be disallowed. The Commission finds that witness Kee's recommendation appears to be based on a misinterpretation of N.C. Gen. Stat. § 62-110.7. First, N.C. Gen. Stat. § 62-110.7(b) includes the word "may" indicating that it is at the utility's discretion whether it will seek to incur approval of its decision to incur nuclear project development costs under the statute. Costs for which preapproval is not sought, such as those in 2010, are still appropriately considered in a general rate case proceeding under N.C. Gen. Stat. § 62-133, including the prudence of the decision to incur the costs. Similarly, the costs that were incurred outside the cap set in the

2011 Order are appropriately considered in this proceeding. N.C. Gen. Stat. § 62-110.7 provides a utility approval only of its decision to incur nuclear development costs under the circumstances at the time of the decision. No particular costs are approved or found to be reasonable, and circumstances can change after issuance of the approval making it no longer reasonable to incur costs. As discussed by DEC witness Fallon, DEP elected to pursue development of its Harris Nuclear project without obtaining approval under N.C. Gen. Stat. § 62-110.7 and the Commission approved recovery of the costs of the COLA in DEP's recent rate case without regard to whether DEP had received approval under N.C. Gen. Stat. § 62-110.7. The Commission further disagrees with witness Kee that what he categorizes as Type 2 costs should be disallowed because they were not necessary to maintain the status quo. The Commission finds that, except as discussed above in regard to the visitors' center and AFUDC, the costs were reasonably and prudently incurred to maintain the status quo and ensure that Lee Nuclear would be an option for the dates of projected need in DEC's IRPs.

B. Cancellation of the Lee Nuclear Project

The Company has stated that it seeks Commission approval to cancel the Lee Nuclear Project. The Commission agrees with DEC witness Fallon that the risks and uncertainties in regard to beginning construction of the Lee Nuclear Project, including the Westinghouse bankruptcy, issues with Toshiba, the cancellation of the Summer project, overruns and delays at the Vogtle project, as well as natural gas prices and potential carbon emissions regulation, have become so great that cancellation is in the best interest of customers. Further, DEC's 2017 IRP does not show a need for the first unit until 2031, and then only under a number of assumptions.

While no party expressed opposition to DEC's decision to cancel the Lee Nuclear Project, in their proposed orders, the Tech Customers and the Public Staff question the authority of the Commission to cancel the project noting that the Commission had never granted the project a CPCN under N.C. Gen. Stat. § 62-110.1, nor had any other state approved the project. While there may be merit to such observations, suffice it to say, the Commission finds and concludes that adequate justification exists to support cancellation of the Lee Nuclear Project and that DEC's decision to cancel the project is reasonable and prudent and in the public interest.

C. Return on Unamortized Balance

The Commission is also in agreement with Public Staff witness Boswell's position concerning the Company's request to earn a return on the unamortized balance of the costs. Company witness McManeus acknowledged on cross-examination that in the cases of Duke Power Co., Docket No. E-7, Sub 338, 72 N.C.U.C. 173 (Nov. 1, 1982); Carolina Power & Light Co., Docket No. E-2, Sub 461, 73 N.C.U.C. 114 (Sept. 19, 1983); and Carolina Power & Light Co., Docket No. E-2, Sub 481, 74 N.C.U.C. 126 (Sept. 21, 1984), all involving abandoned nuclear plants, the Commission had refused to allow a return on the unamortized balance. She further stated that she knew of no other case decided since 1982 approving a return on the unamortized balance; and neither the Public

Staff nor the Commission has been able to identify any such case. The Commission's 1982-84 decisions denying a return on the unamortized balance of nuclear plant costs have been reaffirmed in cases such as Carolina Power & Light Co., Docket No. E-2, Sub 537, 78 N.C.U.C. 238 (Aug. 5, 1988), aff'd in part, rev'd in part on other grounds, and remanded sub nom. State ex rel. Utils. Comm'n v. Thornburg, 325 N.C. 484, 385 S.E.2d 463 (1989). See also, State ex. rel. Utils. Comm'n v. Thornburg, 325 N.C. 463, 480-81, 385 S.E.2d 460-61 (1989), which held that the Commission had the legal authority to deny a return on the unamortized balance of nuclear cancellation costs.

In the Commission's judgment, the decisions it has reached on this issue since 1982 are correct and should be followed in this case. The Commission has repeatedly decided that the loss experienced upon the cancellation of a nuclear plant should be shared between the shareholders and the ratepayers. As the Commission stated in its Order in Duke Power Co., Docket No. E-7, Sub 358, 73 N.C.U.C. 255, 266 (Sept. 30, 1983), when addressing the loss associated with the Cherokee Nuclear Plant (Lee's precursor abandoned nuclear project at the same site):

> It would be inequitable to place the entire loss of expenditures that were prudent when made on the utility. Thus, amortization should be allowed. However, on the other hand, the ratepayer must not bear the entire risk of the Company's investment. A middle ground must be found on which the Company bears some of the risk of abandonment and the ratepayer is protected from unreasonably high rates.

See also, In re Carolina Power & Light Co., Docket No. E-2, Sub 461, 55 P.U.R. 4th 582, 601 (1983).

Accordingly, regulatory commissions in North Carolina and many other states have allowed the utility to recover the costs of an abandoned plant through amortization, while excluding the unamortized balance from rate base. In this way, a fair allocation of the losses is accomplished: the ratepayers are required to bear the losses resulting directly from the cancellation, while the shareholders must absorb the loss associated with the delay in receiving their compensation. This is the policy that the Commission adopted in Duke Power Company's case in November 1982; we have consistently adhered to it in the years since, and we see no valid reason to depart from it now.

The Commission does not agree with witness Fallon that the Company's receipt of three PDOs should factor into whether it should receive a return. The Commission notes that the Company chose to act without a PDO in 2010 and after the second quarter of 2013, over one third of the period of the project, thereby acting outside of the requirements of and protections offered by N.C. Gen. Stat. § 62-110.7. While N.C. Gen. Stat. § 62-110.7 is permissive and the Commission has found that the Company's Lee Nuclear incurred costs and activities were reasonable and prudent (except as discussed above in regard to the visitors' center and AFUDC) regardless of whether it received PDOs for the entire period, DEC's receiving Commission approval of some of its decisions to incur nuclear project development costs does not factor into the Commission's exercise of its discretion under N.C. Gen. Stat. § 62-110.7(d) as to whether the Company should get a return on the unamortized balance of the Lee Nuclear costs.

Additionally, the Commission rejects the contention by witness Fallon that having obtained a COL should merit shifting the entire burden of cost and risk to ratepayers. While the Commission agrees that the COL has value, that value will only be realized if the plant is built. Pursuant to the 2017 IRP, that possibility would occur only under very limited circumstances. Moreover, there is a cost to maintaining this option that DEC will likely be requesting ratepayers to bear in future rate cases.

Further, in Docket No. E-2, Sub 1035, DEP sought a deferral on its Harris COLA costs, but requested no return on the unamortized balance, citing <u>State ex rel. Utils. Comm'n v. Thornburg</u>, 325 N.C. 463, 385 S.E.2d 451 (1989) (holding that NCUC had authority to allow CP&L to recover capital investment in cancelled plants through 10-year amortization, with no return on the unamortized balance); <u>Order Approving Stipulation and Deciding Non-Settled Issues</u>, Docket No. E-7, Sub 828 (December 20, 2007) (treating GridSouth costs as an abandonment loss and allowing recovery of prudently-incurred costs over a 10-year amortization period, with no return on the unamortized balance); and <u>Order Approving Partial Rate Increase</u>, Docket No. E-7, Sub 358 (September 30, 1983) (allowing Duke Power to recover abandonment loss due to Cherokee Nuclear Units 1-3 cancellation over a 10-year amortization period, with no return on the unamortized balance). The Commission sees no reason to treat the Lee Nuclear Project differently, regardless of the difference in costs or achievement of a COL.

The Commission also notes that in its proposed order, for the first time in this proceeding, DEC argues that the Commission specifically made a distinction that it would treat the Lee Nuclear project development costs differently for purposes of ratemaking in its 2007 Order and that the General Assembly codified that distinction when it did not prohibit a return on the unamortized balance of prudently incurred costs during the amortization of a cancelled plant in N.C. Gen. Stat. § 62-110.7(d). In fact, DEC now argues that the principles of statutory construction that it weaves between N.C. Gen. Stat. § 62-110.7(c) and 110.7(d) support the Company's position that it should earn a return on the costs invested to develop the Lee Nuclear Project, even though it is cancelled. With respect to DEC's argument in these regards, the Commission simply disagrees. First, the Commission can unequivocally state that nothing in its 2007 Order spoke directly to or implied support for the Company to be able to earn a return on the unamortized balance. The Commission also notes that DEC's own witnesses testified that it was within the Commission's discretion whether or not to allow a return on the unamortized balance. Further, since the Lee Nuclear Plant is now cancelled, the term "…the potential nuclear plant…" that appears in N.C. Gen. Stat. § 62-110.7(c) is no longer applicable to the issue at hand, and N.C. Gen. Stat. § 62-110.7(d) is now controlling and there is no mention in N.C. Gen. Stat. § 62-110.7(d) regarding a return on the unamortized balance. In addition, although not applicable here, N.C. Gen. Stat. § 62-110.6(e), regarding rate recovery for construction costs of out-of-state electric generating facilities that are cancelled, directs the Commission to provide cost recovery as provided in N.C. Gen. Stat. § 62-110.1(f2) and (f3). N.C. Gen. Stat. § 62-110.1(f2) and (f3) include the provision that "…the Commission shall make any adjustment that may be required because costs of construction previously added to the utility's rate base pursuant to subsection (f1) of this section are removed from rate base and recovered in accordance with this subsection." (emphasis added) This analogous portion of the statute makes clear that costs associated with canceled plant are not part of rate base and the Commission determines to interpret N.C. Gen. Stat. § 62-100.7 which is silent as to the issue similarly. In summary, the Commission has carefully reviewed DEC's contentions that any prior Commission order or the ratemaking treatment prescribed in N.C. Gen. Stat. § 62-110.7(c) is supportive, applicable, or controlling with respect to allowing a return on the unamortized balance and disagrees.

Finally, although not discussed in the record, the Commission notes that during the entire 12-year period in which DEC incurred and funded the project development costs, it was allowed to accrue an AFUDC return. In fact, AFUDC comprises over forty percent of the total Lee Nuclear project development cost. The accrual of the AFUDC has already provided DEC, or its investors, a return on all non-AFUDC costs incurred during the past 12 years and that return will be recovered in cash from ratepayers over the next 12 years as the total allowed cost is amortized. The Commission concludes this consideration is supportive of its decision to require a fair allocation of costs for the cancelled plant between the Company and its ratepayers by denying a return on the unamortized balance during the 12-year amortization period.

D. Summary of Conclusions on Lee Nuclear

In summary, the Commission concludes in regard to the Lee Nuclear Project that the costs were reasonably and prudently incurred except the costs of the architectural and engineering design of a visitors' center and AFUDC after December 31, 2017. The Commission finds that it is reasonable and prudent for the Company to cancel the Lee Nuclear Project at this time. Finally, the Commission holds that the costs of the Lee Nuclear Project should be recovered through amortization over a period of 12 years, with no return on the unamortized balance.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 50-51

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1, the direct testimony of Public Staff witnesses Robert Hinton and Michael Maness, the rebuttal testimony of Company witnesses Stephen De May and David Doss, and the entire record in this proceeding.

Background of the Nuclear Decommissioning Trust Fund

Every nuclear power plant owner in the United States is required under rules promulgated by the NRC to ensure that the nuclear plants it owns and operates are properly decommissioned when they reach the end of their useful lives. Monies to pay for decommissioning activities are collected from customers in rates and deposited in trust funds, where they are invested and earn returns.

DEC operates seven nuclear-powered units at three different power plants. Funds the Company has collected in rates from customers over the years, pursuant to specific authorizations contained in rate orders issued by this Commission, have been deposited in nuclear decommissioning trust funds (while each nuclear unit has its own decommissioning funds held in trust, for ease of reference, they are herein referred to collectively as the (NDTF)) pursuant to the NRC rules. Under those rules, as well as rules promulgated by the IRS, NDTF funds are to be used exclusively for nuclear decommissioning activities, which include license termination, dealing with spent fuel, and site restoration.

Through procedures described in greater detail below, every five years the Company engages a third-party consultant to perform a site-specific study and prepare a site-specific estimate of the decommissioning costs which will be necessary to decommission the units DEC owns and operates. Based upon that study, the Company files a report setting out those estimates (the Decommissioning Cost Study Report, or Cost Report). Every five years, based upon financial assumptions provided by additional third-party consultants, the Company models NDTF balances at the time of decommissioning and files a report in a prescribed format (the Decommissioning Cost and Funding Report, or Funding Report) detailing the total revenue requirement/decommissioning expense needed to fund its decommissioning obligations.

The Company last filed a Cost Report and Funding Report in 2014. Those Reports indicated that based upon projected decommissioning costs and projected NDTF balances (both projected decades into the future, inasmuch as decommissioning will not take place until decades into the future), the NDTF was adequately funded. Tr. Vol. 12, p. 48. Accordingly, the Company concluded that, at least as of that time, the Company need not collect in rates any cost with respect to nuclear decommissioning, and that additional contributions to the NDTF need not be collected from customers. The Company has not collected any NDTF contributions from customers since January 1, 2015.

Thereafter, with the joint support of the Company and the Public Staff, the Commission implemented a decrement rider as of July 1, 2015, reducing the Company's revenue requirements in order to reflect nuclear decommissioning costs at $0. In this rate case, based upon standard escalations of the 2014 Cost Report and 2014 Funding Report, the Company again concluded that the NDTF was adequately funded and determined that it need not collect any nuclear decommissioning expense as part of its cost of service.

In this docket, the Public Staff has taken the position that the NDTF is overfunded by $2.35 billion. The Public Staff asserts that in order to redress this supposed overfunding, the Company should be required to refund the excess by assigning to nuclear decommissioning "expense" a value of ($29 million) – that is, negative $29 million – per year. Acknowledging that the funds in the NDTF are untouchable for this purpose, in that they are to be used solely for decommissioning, the Public Staff developed a proposal by which the funds would be refunded to customers through the mechanism of a "loan" to be "repaid" after decommissioning is complete.

DEC contends the NDTF is not "overfunded." Further, as discussed below, under generally accepted accounting principles (GAAP), the Company believes it would have to write off the proposed "loan" inasmuch as it would not have a probable and acceptable path to repayment. DEC also argues that the approach recommended by the Public Staff is retroactive in nature, thus violating the prohibition against retroactive ratemaking in North Carolina. Finally, DEC submits prior orders of this Commission including prior agreements between the Public Staff and the Company appropriately provide for addressing surplus decommissioning funds – if any – at the conclusion of decommissioning.

Summary of Evidence Relating to NDTF

On July 25, 1988, the Commission opened Docket No. E-100, Sub 56 (Sub 56 Docket) to consider issues relating to decommissioning cost and funding for nuclear power plants owned and operated by the public utilities under its jurisdiction, namely Carolina Power & Light Company (now DEP), Duke Power Company (now DEC), and North Carolina Power (now Dominion North Carolina Power).[40]

On November 3, 1998, the Commission issued an Order in the Sub 56 Docket (Order Approving Guidelines (DEC – Maness Cross-Examination Ex. 1, Tab 1)), in which it adopted guidelines for the determination and reporting of nuclear decommissioning costs (the Guidelines). The Guidelines establish the five-year cycle of report filing described above, with respect to both the Cost Report, where the Company estimates decommissioning costs, and the Funding Report, detailing the total revenue requirement/decommissioning expense needed to fund the Company's decommissioning obligations. Further, as Public Staff witness Maness confirmed, the Public Staff is provided a 90-day period to issue discovery and investigate the cost and funding analysis the Company sets out in its Reports. Tr. Vol. 22, pp. 185-86. The Public Staff then has 90 days to prepare and file its own report. Id. In accordance with the Guidelines, the Public Staff has routinely reviewed the Company's decommissioning Cost Reports and decommissioning Funding Reports.

In the Company's last rate case, it proposed that nuclear decommissioning expense be $35 million. See 2013 DEC Rate Order, p. 110; DEC – Maness Cross Examination Ex. 1, Tab 3. The Public Staff, through witness Hinton, proposed an adjustment to reduce that expense to $14.6 million, which the Company accepted and the Commission ordered. Id. at 111. In the following year, the Company's five-year Cost Report/Funding Report cycle required it to file those Reports. As noted above, the Company concluded in connection with those filings that the NDTF was adequately funded and that a decrement rider to reduce nuclear decommissioning expense to $0 as of January 1, 2015 was warranted, which the Commission ultimately ordered. DEC – Maness Cross Examination Ex. 1, Tabs 2 and 4; Tr. Vol. 22, pp. 189-92.

As required by the Guidelines, the Public Staff investigated the 2014 Cost Report and the 2014 Funding Report, as well as the Company's suggestion that nuclear

[40] The Chairman ruled that the Commission would take judicial notice of the filings in the Sub 56 Docket in this proceeding. Tr. Vol. 22, p. 183.

decommissioning expense be reduced to $0 through a decrement rider. Tr. Vol. 22, p. 193. Its investigation was thorough, and the report that it prepared pursuant to the Guidelines was likewise thorough and well thought-out. Id. at 194. In that report (Public Staff Report; DEC – Maness Cross-Examination Ex. 2), the Public Staff noted that the NDTF fund balance would exceed estimated decommissioning costs at license termination[41] on a North Carolina retail jurisdictional basis by $2.5 billion. Id. at 11-12. The Report further indicated in its "Conclusions and Recommendations" section that the Public Staff had completed its investigation of the Cost Report and the Funding Report, had reviewed the Company's responses to data requests, and had no disagreement with the Company "regarding the calculation and implementation of the $0 expense/revenue requirements or any other aspect of its decommissioning cost and funding activity." Id. at 12. The Public Staff Report then concluded that apart from the implementation of the decrement rider, "the Public Staff has no recommendations for further action by the Commission in this matter." Id. (emphasis added).

In this rate case, the Company again determined that the nuclear decommissioning expense in its cost of service was $0. Tr. Vol. 12, p. 49. The Public Staff, however, asserted, through witness Hinton, that the NDTF was overfunded by $2.35 billion. Tr. Vol. 22, p. 252. The Public Staff proposed that these "excess" funds be returned to customers, and that this could be accomplished by reducing North Carolina retail expense by $29.1 million. Id. at 260.[42]

Under applicable NRC and IRS regulations, these funds could not be simply withdrawn from the NDTF, a fact recognized by Public Staff. Id. at 252. It indicated instead, through witness Maness, that if the Company "cannot remove such funds from the NDTF, its shareholders will be required to provide (i.e., loan) the funds for the expense reduction …." Id. at 105 (emphasis added). Witness Maness added that this loan would be "on a temporary basis." Id. Company witness Doss testified, "if the Public Staff's recommended rate-making mechanism is approved, and if actual experience mirrors the projections on which the Public Staff's recommended refunds are based, the Company would not be entitled to collect on the loans to ratepayers until funds could be withdrawn from the NDTF upon the completion of nuclear decommissioning activities, which is currently expected to occur in approximately 50 years." Tr. Vol. 12, p. 60.

Discussion and Conclusions

The key factual predicate to the Public Staff's recommendation is that the NDTF is overfunded. The facts in this case indicate that it is premature to reach such a conclusion. The Public Staff's principal proponent of the notion that the NDTF is overfunded – witness Hinton – did not testify that this is the case in absolute terms. Rather, his testimony is hedged with qualifiers: "Assuming the projected decommissioning costs and earning returns … are

[41] Measurement at license termination is the manner in which the Guidelines require the Funding Report to be filed. See DEC – Maness Cross-Examination Ex. 1, Tab 1, Attachment 1.

[42] Witness Hinton's direct testimony indicated that this figure was $19.4 million (Tr. Vol. 22, p. 252), but he discovered an error in his analysis and corrected the figure to $29.1 million Id. at 260.

accurate through when DEC's last nuclear unit is decommissioned, the NDTF is currently over-funded by $2.35 billion." Tr. Vol. 22, p. 252 (emphasis added). A number of qualifiers and the uncertainty regarding future events underlie witness Hinton's conclusion that the NDTF is currently overfunded. Id. However, witness De May testified that on an NC retail basis, the NDTF is actually underfunded as of the end of the test year:

> [T]he NDTF balance was $2.19 billion as of December 31, 2016. The estimated decommissioning cost (in 2016 dollars) as of December 31, 2016 was $2.46 billion. In other words, on a current dollars basis, the NDTF was approximately 89% funded as of December 31, 2016.

Tr. Vol. 4, pp. 79-80.

Witness De May further testified that the Company uses three methods to determine whether the funding levels in the NDTF are adequate such that the nuclear decommissioning portion of cost of service should be assigned a zero-dollar cost. One is the "current value" method, which is what is described above. Another is the "projected value" method, which is the basis of witness Hinton's conclusion. The projected value method measures, as its name suggests, the funds in the NDTF projected as of the end of decommissioning, still decades into the future, compared to projected costs, again decades into the future. In other words, the projected value method measures "the projected balance of the NDTF at the end of the decommissioning period, i.e., after all decommissioning activities are completed, and is in future dollars (ranging from 2058 through 2067)." Id. (emphasis added). Witness De May testified that this measure indicates whether the NDTF is adequately funded, but does not indicate that it is fully funded – for that, one cannot know "until the last dollar is spent on decommissioning." Id. at 568.

The third method witness De May described is the "probability of success" method. This method, witness De May explained, uses a probability of success ratio to evaluate the likelihood of having sufficient funds to fully decommission each nuclear unit. Id. at 80. This approach involves 5,000 Monte Carlo simulations of market returns and escalation factors between the time of analysis and the end of decommissioning and generates a percentage of scenarios for which funding is adequate to meet all future decommissioning obligations. Id. Witness De May testified that "[a]s of December 31, 2016, the nuclear unit probability of success ratios ranged from 77% to 85%, depending on the unit; conversely, the probability of not having sufficient funds to decommission the nuclear units ranged from 15% to 23%." Id. (emphasis in original). Although these percentages may support a determination that no additional funding from ratepayers is currently required to fund the NDTF, the Company submits that in no way should this be interpreted as supporting a view that the NDTF is "overfunded."

The Company based its determination that the NDTF funding levels were adequate and that, as a consequence, it would not request any nuclear decommissioning cost in its revenue requirements in this case, on the fact that the NDTF has experienced higher than expected returns recently and that the escalation rate assumption has remained modest. Id. at 82. There is, of course, no assurance that these conditions will extend into the future, and certainly no assurance that they will extend decades into the future. Uncertainty is further compounded by timing, as license extensions or unforeseen circumstances could accelerate or push out the plants' retirement dates. Insofar as escalation rates are concerned, witness De May testified that the model used to estimate funding requirements is highly sensitive to changes in the escalation rate assumption, and that an "increase in the forecasted escalation rate from 2.40% to 3.09%, a 0.69% increase, fully eliminates the projected NDTF overfunded balance at the end of the decommissioning period." Id. He noted that for the period 1913-2017, the average consumer price index (CPI-U) rate has been 3.24%. Accordingly, changing the escalation rate from the currently model rate of 2.4% just to the average CPI-U increase over the past hundred years means that the Public Staff's projected $2.35 billion overfunding disappears. Id. at 587.

He also testified regarding returns, "You probably hear this all the time in investment jargon, past returns are not an indication of future results." Tr. Vol. 5, p. 58. A 2015 Public Staff Report (DEC – Maness Cross-Examination Ex. 2), noted:

> The current healthy financial position of the … [NDTF] relative to estimated costs results largely from significantly higher than expected trust fund investment returns that have been experienced in recent years. The trust fund has not, however, always experienced such strong investment returns, and in fact, there have been many years of low or negative investment returns.

Id. at 13.[43]

Witness Hinton attempts to address concerns that the Public Staff's recommendation would lead to future underfunding by asserting that there are sufficient regulatory protections to avoid any significant under recovery in the NDTF. Tr. Vol. 22, p. 252. However, DEC contends that this statement ignores that some of those protections include restrictions preventing withdrawals from the NDTF. As witness De May indicated,

> [T]here is a reason it's illegal to take money out of the trust. It's because … [the NDTF is] not an investment account, it's not a savings account. It's there for the very good public policy of decommissioning nuclear power plants ….

Tr. Vol. 4, p. 588.

In light of all of the evidence presented, the Commission determines that it is premature to find and conclude that the NDTF is overfunded. While the funding model that is used to determine the annual nuclear decommissioning expense forecasts that under various assumptions, the NDTF may be overfunded by approximately $2.4 billion,

[43] For example, industry-wide from 2006 through 2008, the financial markets had a significant negative impact on trust fund balances. See NRC Office of Nuclear Regulation, 2009 Summary of Decommissioning Funding Status Reports for Nuclear Power Reactors (SECY-09-0146, October 6, 2009), p. 7, available online at: https://www.nrc.gov/docs/ML0925/ML092580041.pdf. The Commission takes judicial notice of this NRC report.

the evidence also indicates that on a current dollar basis it is only 89% funded. The Commission agrees with witness De May's concern that returning the projected excess funds to ratepayers now could lead to underfunding of the NDTF in the future. The record shows that the NDTF has experienced higher than expected returns recently, and the escalation rate used to forecast decommissioning costs has remained modest compared to historical rates of inflation, both of which have contributed to favorable results. Changes in assumptions for variables, including investment returns, escalation rates and decommissioning start or completion dates, will all impact future NDTF funding levels, as will deviation of future experience from current forecasts. In the judgment of the Commission, while the NDTF is currently adequately funded, it is premature to find and conclude that the NDTF is overfunded, and therefore, it would not be prudent to return funds to customers at this time, and perhaps for several years, even if it were legally permissible to do so.

Given the Commission's finding and conclusion in this regard, it is not necessary for the Commission to address the related issues between the parties regarding GAAP treatment, retroactive ratemaking and prior agreements.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 52-55

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of DEC witnesses Spanos, Doss, and Kopp, Public Staff witness McCullar, and the entire record in this proceeding.

Company witness Doss introduced Doss Exhibit 3, the revised depreciation study filed in this docket (Depreciation Study), as prepared by Gannett Fleming Valuation and Rate Consultants, LLC. Tr. Vol. 12, p. 56. As explained by witness Doss, the Depreciation Study included updates to estimates of final plant depreciation costs for steam, hydraulic, and other production plants, as well as updated forecasted generation plant retirement dates. Id. at 77. In addition, witness Doss introduced Doss Exhibit 4, the Decommissioning Cost Estimate Study (Decommissioning Study) prepared by Burns and McDonnell Engineering Company, Inc. (Burns & McDonnell), an external engineering firm. This report included estimates for final decommissioning costs at steam, hydraulic, and other production plants.

DEC witness Doss testified that the updated depreciation rates for various fossil and hydro plants reflect changes in the probable retirement dates to align with current licenses, industry standards, or operational plans due to aging technology, assumptions for future environmental regulations, or new planned generation. Tr. Vol. 12, pp. 51-52. In addition, the Depreciation Study incorporates generation assets that have been placed in service since the last study, as well as the W.S. Lee Combined Cycle Plant, once it goes into service. Id. at 52. Additionally, the rate for meters to be replaced under the Company's Advanced Metering Infrastructure (AMI) deployment was updated to allow recovery of the net book value over three years. Id. The Depreciation Study uses a 15-year average service life for the new AMI meters being deployed, increasing depreciation expense. Id. Finally, witness Doss also notes that there is a net decrease in the depreciation expense for distribution, transmission, and general plant assets, primarily driven by longer average service lives for assets such as overhead and underground conductors and services. Id.

Public Staff witness McCullar and CIGFUR III witness Phillips also made recommendations related to depreciation expense. Witness McCullar recommended several adjustments to the Company's proposed depreciation rates including adjustments to future terminal net salvage costs (also known as decommissioning and dismantlement costs), to other production plant interim net salvage percentages, and to remove inflation from terminal net salvage costs. Tr. Vol. 26, pp. 777-78, 783-85. Witness McCullar testified that based on December 31, 2016 investments, DEC was proposing an increase in its depreciation annual accrual of $81,480,296. Tr. Vol. 26 p. 773. Based on Public Staff witness McCullar's investigation, the Public Staff recommended an increase in DEC's depreciation annual accrual of $20,709,566 based on December 31, 2016, investments, a decrease of $60,770,730 from the amount proposed by the Company. Tr. Vol. 26, p. 775. The difference between the Company's and the Public Staff's proposed depreciation annual accrual results from four adjustments proposed by witness McCullar, and one recommended by Public Staff witness Maness, as discussed below. Finally, witness Phillips recommended that changes in the depreciation rates should net to a zero-dollar impact.

Estimated Terminal Net Salvage Costs – Contingency

Burns & McDonnell conducted the Decommissioning Study for DEC, which formed the basis for DEC's terminal net salvage cost estimates. In that study, a 20% contingency for future "unknowns" was included in DEC's estimate of future terminal net salvage costs. "Public Staff witness McCullar recommended that the 20% contingency for future "unknowns" included in DEC's estimate of future terminal net salvage costs be eliminated. Tr. Vol. 26, p 778. Witness McCullar explained that including a 20% contingency factor puts the risk of possible future unknowns on current ratepayers. Id. Witness McCullar pointed out that DEC has not identified actual future costs to be covered by the contingency, but estimates future terminal net salvage costs based on anticipated contractors' bids for dismantlement of equipment, addressing of environmental issues, and restoration of the site, and then adds 20% for unknown costs that DEC cannot specifically identify. Tr. Vol. 26, pp. 778-79. Public Staff witness McCullar testified that putting all the risk of "estimated future unknown unidentified costs" on current ratepayers was inappropriate and recommended a contingency of 0%. Tr. Vol. 26, p. 780. In response to witness McCullar's recommendation, DEC witness Kopp explained why a 20% contingency is appropriately included in DEC's Decommissioning Study. He explained that contingency protects customers by ensuring more accurate estimates of the costs of terminal net salvage to be incurred in the future. Tr. Vol. 10, p. 108. He stated that while these costs could not be specifically identified, it was reasonable to expect them to be incurred. Id. Witness Kopp explained that direct decommissioning costs were estimated based on performing known tasks under ideal conditions. Tr. Vol. 10, p. 109. However, Company witness Kopp admitted that Burns & McDonnell did not obtain any firm quotes for DEC facilities, but used unit pricing or its experience. Tr. Vol. 10, p. 137.

Further, according to witness Kopp, the contingency was added to recognize the likelihood of cost increases for unknown costs. Id. He pointed out uncertainties in work conditions, scope of work, the manner in which work would be performed, estimating quantities, weather, and unknown contamination, among other things. Tr. Vol. 10, pp. 109-10. DEC witness Kopp testified that inclusion of contingency costs was standard industry practice. Tr. Vol. 10, p. 110. He explained that a 20% contingency was appropriate at a site where power had been generated for years and where there was likely to be more environmental contamination, and thus was based on the level of risk of additional contamination. Tr. Vol. 10, pp. 111-12. Witness Kopp pointed out that there had been no on-site testing for hazardous materials or environmental contamination, no sampling of groundwater, no subsurface investigation, no asbestos inventories, and that the cost estimates included only a minimal level of environmental remediation. Tr. Vol. 10, pp. 111-12. Company witness Kopp contended that it would not be prudent to try to develop estimates that were more accurate or precise so that a smaller contingency would be reasonable, because of the high cost of conducting such a study and the limited time that the cost estimates could be considered reliable. Tr. Vol. 10, p. 113. Yet he argued that while these estimates were not precise enough to develop a more reasonable contingency, they were precise enough on which to base depreciation rates. Tr. Vol. 10, pp. 113-14. DEC witness Kopp noted that Burns and McDonnell had performed a decommissioning study for DEP in 2012, and that study's estimates for the decommissioning and demolition of Cape Fear, H.F. Lee, Sutton, Robinson, and Weatherspoon plants forecast costs 11% lower than actually incurred. Tr. Vol. 10, p. 114.

Accordingly, witness Kopp explained that a 20% contingency on these costs is both reasonable and warranted based on the risk level associated with the decommissioning projects. As the Company pointed out in its Response to Public Staff Data Request No. 17, the anticipated contractor's bid is based on performing known dismantlement tasks under ideal conditions. Id. at 116. (emphasis added) Witness Kopp contended that Public Staff witness McCullar had not taken into account that the direct costs were based on known tasks occurring under ideal conditions. Tr. Vol. 10, pp. 115-16. Witness Kopp also pointed out the minimal level of investigation Burns & McDonnell made into the existence and costs of potential environmental contamination and remediation, which he argued supported a 20% contingency. Tr. Vol. 10, p. 116. Regarding witness McCullar's contention that the Company should not recover a contingency for costs that cannot be identified at this time, witness Kopp agreed that specific future costs could not be identified, but noted that some typical costs that might be incurred or that have been incurred on similar projects were known. Tr. Vol. 10, pp. 117-18.

On cross examination, Company witness Kopp indicated that the Decommissioning Study did not take into account the impact of any planned changes to convert the Belews Creek, James E. Rogers (Cliffside), and Marshall plants to dual fuel capability as planned by the Company (Spanos/Kopp Cross Exhibit 1), which could increase or decrease the study's estimates. Tr. Vol. 10, pp. 127-29. Neither did the study take into account any changes in steel and aluminum prices that might occur due to imposition of tariffs. Tr. Vol. 10 pp. 133-34. Witness Kopp also stated that decommissioning and demolition was the most prudent option at the end of a plant's useful life, but acknowledged sale of a plant as another option. See Duke Energy's announcement of the sale of its retired Walter C. Beckjord coal-fired power plant, Spanos/Kopp Public Staff Cross Exhibit 3. Tr. Vol. 10, pp. 131-33.

In his testimony, DEC witness Kopp testified that, "[a]s engineering design for demolition progresses and some of these unknowns can be determined through subsurface investigations, asbestos sampling, and engineering specifications, the amount of contingency may be reduced; however, contingency would never be completely eliminated." Tr. Vol. 10, pp. 112-13. He also stated that the "Company performed no subsurface investigations, asbestos inventories, or groundwater sampling to identify and define remediation requirements during this planning phase." Tr. Vol. 10, p. 112. However, on cross-examination, witness Kopp admitted that the Company did perform asbestos inventories. Tr. Vol. 10, p. 136. But instead of relying on studies that had been performed, "Burns and McDonnell did not rely upon these historical studies ...." Tr. Vol. 10, p. 136.

DEC witness Kopp highlighted all the environmental testing that has yet to be done and all the uncertainties inherent in the study. While the Decommissioning Study was conducted based on data from 2016 and 2017, DEC has since announced plans to convert three of its plants to dual-fuel capability, changing some of the assumptions in the study. While it is impossible to anticipate all future costs, merely being able to identify possible future costs or costs incurred for other projects is not the most firm basis on which to calculate contingency. This causes some concern for the Commission.

The Commission takes note that the Company failed to take into account the possibility that scrap prices may increase or that the production plant may be repurposed, or sold. Further, DEC witness Kopp's claim that a contingency is needed to account for the unknown of asbestos is not fully supported by the record in this proceeding, since DEC has performed asbestos inventories and identified an asset retirement obligation for these legal asbestos abatement obligations. See Kopp/Spanos Public Staff Exhibit 4. Identifying these costs should reduce the unknown of asbestos and thus reduce any contingency.

Based on the above discussion and all of the evidence in the record, the Commission finds that the contingency proposed for net terminal salvage in this proceeding of 20% is improper and should be reduced. While the Commission appreciates the Public Staff's concern for keeping depreciation rates low, the potential for further environmental costs and remediation costs should not be given short shrift, especially in light of other environmental costs that are discussed elsewhere in this Order. However, the Commission acknowledges the arguments that the Public Staff has made, and in an attempt to strike a fair balance, the Commission finds that a 10% contingency factor is fair to all parties. The Commission further notes that in DEP's most recent rate case proceeding, Docket No. E-2, Sub 1142, the Commission approved a 10% contingency factor. The Commission is confident that a 10% contingency factor, while less than DEC's requested factor of 20%, should protect the Company from additional costs it will incur but cannot specify at the present date. The Commission also finds that a 10% contingency factor properly reflects the inclusion of items that should push unknown costs downward (i.e increase in scrap prices, etc.) thereby protecting the ratepayers as well. Based on the foregoing, the Commission concludes that including a contingency factor of 10% should be utilized by the Company.

Cost Escalated to the Date of Retirement

It is important to recover the service value of the Company's assets by determining the net salvage costs that will be incurred in the future. As DEC witness Spanos explained, using the straight-line method of depreciation, these costs are recovered ratably, or in equal amounts, each year over the life of the Company's plant. Tr. Vol. 10, p. 83. This approach is consistent with the Uniform System of Accounts, which specifies that the cost of removal is the actual amount paid at the time the transaction takes place. Id. at 84. As such, including the future cost of net salvage for plant accounts is consistent with established depreciation concepts. In developing decommissioning cost estimates, it is necessary to escalate those estimates to the time period in which the cost is expected to be incurred.

Public Staff witness McCullar testified that the Company took the estimated future terminal net salvage costs from the Decommissioning Study, which are in year 2016 dollars, and inflated them to the year of the assumed retirement of the production plant. She testified that DEC proposes to collect these inflated amounts in today's more valuable dollars from ratepayers. Tr. Vol. 26, pp. 780-81. Witness McCullar's Exhibit RMM-2 showed how for the Cliffside plant, the estimated terminal net salvage cost of $48,075,000 in year-2016 dollars was inflated to $105,945,645 in year-2048 dollars, assuming an annual inflation rate of 2.5% to 2048, the estimated year of retirement, increasing the estimated net salvage cost by a factor of 2.2. Tr. Vol. 26, p. 781. DEC proposes to begin collecting this $105,945,615 calculated using year-2048 dollars from current ratepayers, who would be paying in current dollars. Id. Public Staff McCullar contended that it would be unreasonable in this case to collect these inflated costs of removal in current dollars because it imposes too much risk on ratepayers due to the significant period of time over which the inflation is estimated. Tr. Vol. 26, p. 282.

Witness McCullar recommended that DEC should inflate the terminal net salvage costs to the year 2023, or the retirement date, whichever occurs first. Witness McCullar testified that she selected 2023 because it aligned with the time when the Company is expected to file its next rate case. Witness McCullar stated, "since depreciation rates approved in this proceeding are expected to go into effect in 2018, the year 2023 would be five years later, by which time depreciation rates would have been reviewed in a new base rate case." Tr. Vol. 26, p. 784. Witness McCullar noted that her recommendation reduces the risk on ratepayers associated with paying rates based on extended periods of estimated inflation, while protecting the Company from the risk that it would not be able to collect its net salvage costs. Tr. Vol. 26, p. 784.

Witness Spanos explained that many of the Company's plants will not be retired for many years. Tr. Vol. 10, p. 86. Witness Spanos highlighted the importance of "understanding the Company's expectations for these assets, as well as the estimates within the industry." Id. at 91. Accordingly, the net salvage costs must be escalated so that the correct amounts are allocated over the remaining lives of the plants. Tr. Vol. 10, p. 86. The approach used by the Company to escalate cost is widely supported by authoritative depreciation texts and industry practice. For example, witness Spanos pointed out that the NARUC Manual provides the following:

> Under presently accepted concepts, the amount of depreciation to be accrued over the life of an asset is its original cost less net salvage. Net salvage is the difference between gross salvage that will be realized when the asset is disposed of and the costs of retiring it.

Tr. Vol. 10, p. 88. (emphasis added).

In addition, Wolf and Fitch, another highly regarded authoritative depreciation text, provides further support for the position that inflation is appropriately a part of the future cost of net salvage. Wolf and Fitch also argue against a present value or current value concept. In his testimony, Witness Spanos provided the following passage from Wolf and Fitch:

> Some say that although the current consumers should pay for future costs, the future value of the payments, calculated at some reasonable interest rate, should equal the retirement cost. Studies show that the salvage is often "more negative" than forecasters had predicted.

Tr. Vol. 10, p. 89.

Finally, witness Spanos referenced Accounting for Public Utilities by Robert L. Hahne and Gregory E. Aliff to support the proposition that the Uniform System of Accounts and regulatory definition require net salvage to be estimated at a future price level. Id.

The testimony and evidence presented in this case demonstrates that authoritative texts and sound depreciation practices support escalating terminal net salvage costs to the date that the costs are expected to be incurred. Despite arguing against an approach in which the Company would recover costs over the life of the asset, witness McCullar concedes that some escalation is necessary. In fact, witness McCullar escalated terminal net salvage to the projected date for the Company's next base rate case in her calculations. Further, witness McCullar's escalation rate is entirely dependent on the timing of when the Company files its base rate case and lacks any nexus to the timing of the future retirement of the asset. The Commission notes that the record is void of any accounting literature support for witness McCullar's approach, nor would such an approach be appropriate.

The Commission cannot rely upon the scheduling of rate cases to remedy the flaws in witness McCullar's alternative proposal. Witness McCullar's approach is not supported by sound depreciation methods and would likely result in the under recovery of net salvage costs over the life of the asset. To that end, other state utility commissions have rejected witness McCullar's alternative approach as unsupported. For example, in a recent case before the Washington Utilities and Transportation Commission (WTC), witness McCullar advanced similar arguments against the escalation of terminal net salvage costs along with other recommendation related to depreciation.[44] In rejecting the recommendation, the WTC noted that Public Counsel and witness McCullar provided no response to the critique that witness McCullar's approaches were not supported by authoritative accounting literature.[45] The WTC found witness McCullar's net salvage proposal "[v]ague in its methodology, not supported by authoritative accounting literature, and supported by unwarranted assumptions."[46]

The fact is the vast majority of jurisdictions use a method for net salvage in which future net salvage is estimated at its future cost and recovered through straight-line depreciation (also known as the traditional method). Approximately 46 out of 50 jurisdictions recover future costs using the straight-line depreciation method. The use of this method is also consistent with the treatment of escalation in the most recent DEP rate case. As witness Spanos explained, depreciation should be done in a systematic and rational manner based on information known at the time and consistent with the Uniform System of Accounts. Id. at 165.

Considering all the evidence, the Commission finds and concludes that the escalation of terminal net salvage cost and the use of the straight-line method of depreciation in determining escalation as performed in the DEC Decommissioning Study is just and reasonable, appropriate for use in this case, and is adopted.

Other Production Plant Interim Net Salvage Percent Production Accounts

In this case, DEC witness Spanos testified that he recommended a future net salvage percent of negative 4% for other production accounts. Id. at 90. The estimated future net salvage is part of the annual depreciation accrual, which is credited to the reserve to cover the estimated future net salvage costs. As witness Spanos explained, he established an interim net salvage percent on an account basis and then performed the appropriate calculation in order to get the appropriate weighted interim net salvage, excluding account 343.1. Tr. Vol. 12, p. 143. The net salvage estimates were based on

[44] See Washington Utilities and Transportation Commission v. Puget Sound Energy, Final Order Rejecting Tariff Sheet; Approving and Adopting Settlement Stipulation; Resolving Contested Issues, & Authorizing and Requiring Compliance Filing, Washington Utilities & Transportation Commission, Docket UE-170033 (December 5, 2017) Puget Sound Order.

[45] Puget Sound Order, pp. 50-51.

[46] Id. at 60. The WTC noted further that witness McCullar's "comparison of net salvage accruals to net salvage expenditures PSE incurred during recent years would effectively recover net salvage as an operating expense, not a depreciation expense."

an analysis of historical cost of removal and salvage data, expectations with respect to future removal requirements, and markets for retired equipment and materials. See Doss Exhibit 3 IV-2; Tr. Vol. 12, p. 116. The interim net salvage component is approximately 32% of the utilized net salvage percent for other production plant. Id. at 90. Witness Spanos further testified that he noted that the Public Staff's recommended interim net salvage percentage had been included in the depreciation rate proposed for the Lee Combined Cycle Plant. Id. DEC witness Spanos contended that determining an interim net salvage percentage for other production plant should be based on historical data as well as informed judgment. Id. He stated that Accounts 343 and 344 included large amounts of gross salvage related to older combined cycle facilities not applicable to all assets in the account. Id. Company witness Spanos also stated that the high gross salvage numbers were related to the rotable parts of combined cycle facilities, consistent with DEP. Id.

Public Staff witness McCullar proposed a 0% net salvage value for accounts 342, 343, 344, 345, and 346. She testified that for some accounts, the annual accrual amount that would be accrued for estimated net salvage is several times the annual amount DEC actually incurs for net salvage. Tr. Vol. 26, p. 278. Witness McCullar indicated that the historical analysis has been a positive $12,891,310 per year for the last three years and a positive $8,649,160 per year for the last five years. Witness McCullar explained that these positive net salvage amounts indicated that DEC's booked gross salvage exceeded the Company's incurred costs of removal and thus, DEC did not need to collect interim removal costs for these accounts. As a result, witness McCullar took the position that DEC should utilized a 0% interim net salvage based on DEC's actual experience. Witness McCullar further testified that the 0% interim net salvage would not include the final decommissioning costs. The impact of the Public Staff's proposed adjustments to terminal net salvage contingency and escalation rates and interim net salvage results in a decrease in DEC's proposed depreciation rates as of December 31, 2016, of $13,382,159, as shown on p 14 of Exhibit RMM-1 on the line for Total Production. Tr. Vol. 26, p. 786.

In response, witness Spanos testified that in the case of other production plant, it is critical to understand all the components of the historical data. For example, in Accounts 343 and 344, there are large amounts of gross salvage and corresponding retirements that relate to the early installations of combined cycle facilities which are not applicable to all assets in the account. Tr. Vol. 10, p. 91. As witness Spanos described further, the high gross salvage amounts relate to the rotable parts of the combined cycle facilities, which are handled consistently with DEP's assets. Id. Under cross-examination by Public Staff, witness Spanos explained that Account 343 contains high salvage amounts in years 2014, 2015, and 2016, but using informed judgment, he understood those amounts to be related primarily to rotable parts and associated with combined cycle facilities. Using more than just statistical analysis is necessary to evaluate these production plants; informed judgment must also be relied upon as Witness Spanos did. In recommending the negative 4% interim net salvage percentage, witness Spanos took into account the Company's expectations for the assets as well as the estimates within the industry. Id.

The Public Staff presented evidence on cross-examination of DEC witnesses Kopp/Spanos regarding the Company's proposed positive net salvage percentages in Accounts 343 and 344 were related to rotable parts. Kopp/Spanos Public Staff Cross-Examination Exhibit 7 shows that DEC has established rotable parts in a separate account, Account 343.1. Further, Kopp/Spanos Public Staff Cross Exhibit 8 shows that the Public Staff did not propose any adjustment to the interim net salvage percentage for Account 343.1, Prime Movers Rotable. Additionally, under cross examination, witness Spanos admitted that Account 343.1, containing these rotable parts, was also excluded from the Company's interim net salvage proposal for Accounts 342, 343, 344, 345, and 346. Tr. Vol. 10, p. 143.

Based on the evidence discussed above and the entire record in this case, the Commission finds that the Public Staff's proposal to set an interim net salvage percentage of 0 for Accounts 342, 343, 344, 345, and 346 is reasonable. Historical data show that using a negative value, as was previously set, has resulted in DEC overcollecting its costs. It would be inequitable to charge customers for costs that the utility is unlikely to incur. As discussed previously, the Company has stated publicly that it plans to file multiple rate cases between 2019 and 2023, and therefore, this issue can be reexamined in the next base rate case.

Other Depreciation Recommendations

CIGFUR III witness Phillips recommended that any approved changes to depreciation rates should net to a zero-dollar impact on the level of depreciation expense included in rates. Tr. Vol. 10, p. 94. He further recommended that customers not be burdened at this time by the impact of shortening service lives of generating plants based upon assumptions about changing and evolving environmental regulations. Id.

As DEC witness Spanos correctly asserted, witness Phillips provided no support or justification for his net zero proposal, other than a desire that depreciation rates not increase. Tr. Vol. 10, p. 94. Witness Phillips offered no credible critique of the Company's filed Depreciation Study and provided no alternative analysis. The Depreciation Study demonstrates that current depreciation rates are insufficient and that adjustments are necessary for DEC to recover the full cost of its assets providing service to DEC's customers. Id. at 95.

Furthermore, witness Phillips incorrectly states that depreciation rates have changed due to changes to life spans as a result of environmental regulation. Witness Spanos highlighted that there are a variety of reasons that depreciation rates change over time as evidenced by the Depreciation Study filed in this case. The Depreciation Study includes all of DEC's assets, and changes in depreciation rates occur for many reasons, including updated service life and net salvage estimates, updated historical data, and additions to generating facilities. The Depreciation Study is based upon the available information regarding the Company's assets, and the depreciation rates, therefore, needs to be updated to reflect current circumstances. Tr. Vol. 10, p. 95.

For the foregoing reasons, CIGFUR III witness Phillips' blanket recommendation regarding depreciation rates lacks any conclusive support and is rejected.

Conclusion

In light of all of the evidence presented, the Commission finds and concludes that the depreciation rates proposed by DEC in this case, which are based on the revised Depreciation Study included as Doss Exhibit 3 and the Decommissioning Study included as Doss Exhibit 4, with the exception of the adjustments discussed above, are just and reasonable, fair to both the Company and its customers, and therefore, are approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 56-58

The evidence in support of these findings of fact and conclusions is contained in the testimony and exhibits of Company witnesses De May, Fountain, and McManeus; Public Staff witnesses Boswell, Parcell, and Hinton; Tech Customers witnesses Strunk and Brown-Hruska, NCLM witness Coughlan; Justice Center et al. witness Howat; Kroger witness Higgins; CIGFUR III witness Phillips and the entire record in this proceeding.

The federal Tax Cuts and Jobs Act (the Tax Act) was signed into law on December 22, 2017. Among other provisions, the Tax Act reduced the federal corporate income tax rate from 35% to 21%, effective January 1, 2018.[47] It also repealed the manufacturing tax deduction and eliminated bonus depreciation. The Company filed its application for rate increase on August 25, 2017, many months before the enactment of the Tax Act and, therefore, the revenue requirement the Company requested was based on the pre-Tax Act tax laws.

On January 16, 2018, DEC witness McManeus filed her Second Supplemental Direct Testimony that only included limited discrete changes as a result of the Tax Act relating to the elimination of bonus depreciation and the manufacturing tax deduction. Her filing did not include an adjustment to income tax expense as a result of the decrease in the federal corporate income tax rate, nor did it include any proposal for the return of the protected and unprotected Federal EDIT to ratepayers.

In her direct testimony filed on January 23, 2018, Public Staff witness Boswell included an adjustment to income tax expense to reflect the decrease in the federal corporate income tax rate, as well as to remove the manufacturing tax deduction that was also included in the Tax Act. She stated that at that time, the Public Staff was waiting for information from the Company regarding Federal EDIT and reserved the right to supplement her filing to include the Public Staff's proposal for flow back of Federal EDIT.

[47] In response to the enactment of the Tax Act, on January 3, 2018, the Commission opened a rulemaking docket (Docket No. M-100, Sub 148, i.e. the Tax Docket) for the purpose of determining how the Commission should proceed. In the Order establishing the Tax Docket, the Commission placed all public utilities on notice that the federal corporate income tax expense component of all existing rates and charges, effective January 1, 2018, would be billed and collected on a provisional rate basis.

In rebuttal testimony filed on February 6, 2018, DEC proposed an immediate reduction in the Company's revenue requirement, within the context of this proceeding, to account for the reduction in the federal corporate income tax rate but offered no proposal to return Federal EDIT to ratepayers. Company witness Fountain testified that the passage of the Tax Act "provides the Commission with a unique tool to smooth out customer rate adjustments during a multi-year transition period." Tr. Vol. 6, p. 212. He stated that this could be accomplished by offsetting items such as storm response costs, ongoing coal ash basin closure compliance costs or other environmental compliance costs, or accelerating the depreciation of certain assets, such as the existing AMR meters or coal plants. Tr. Vol. 6, p. 213.

In her rebuttal testimony, witness McManeus testified that the Company opposed witness Boswell's adjustment to reduce income tax expense. Tr. Vol. 6, p 323. Witness McManeus testified that the Company had identified the amount of reduction in annual revenue requirement related to reduced income tax expense and translated the amount into a decrement rate per kWh. Witness McManeus stated that the Company proposed to apply the decrement to North Carolina retail service beginning January 1, 2018, and defer the resulting amount into a regulatory liability, continuing the deferral until new rates are established in this rate case that reflect the benefits of the lower tax expense. Tr. Vol. 6, p. 331.

In supplemental testimony filed on February 20, 2018, witness Boswell presented the Public Staff's proposal regarding the flowback of Federal EDIT. Witness Boswell included three adjustments based on the information provided by the Company. First, she recommended the return of protected Federal EDIT based upon the Company's calculation of the net remaining life of the timing differences, as required under the Internal Revenue Code. For the unprotected Federal EDIT, witness Boswell recommended removing the Federal EDIT regulatory liability associated with the unprotected differences from rate base, and placing it in a rider to be refunded to ratepayers over two years on a levelized basis, with carrying costs. Witness Boswell stated that immediate removal of unprotected Federal EDIT from rate base increases the Company's rate base and mitigates regulatory lag that might occur from refunds of unprotected Federal EDIT not contemporaneously reflected in rate base. Further, she maintained that refunding the unprotected Federal EDIT over two years allows the Company to properly plan for any future credit needs. Tr. Vol. 26, pp. 618-19. Ultimately, during the hearing, the Public Staff modified its proposal to adjust the flowback period from two years to five years. Boswell Second Supplemental Testimony, filed March 19, 2018, Tr. Vol. 26, pp. 637-38. The modified proposal is referred to herein as the Public Staff Proposal.

In response to the Public Staff's original 2-year EDIT flowback proposal, the Company Proposal was made initially in Supplemental Comments, filed March 1, 2018, in Docket No. M-100, Sub 148, a docket that the Commission established on January 3, 2018, in order to gather comments from the utilities it regulates along with the Public Staff and other interested parties, to decide how to implement the Tax Act (Tax Docket). By letter filed the next day, the Public Staff objected to the Company Proposal being made in the Tax Docket, in light of the fact that the Company's general rate case was then open and had not yet gone to hearing. Accordingly, the Company then made its proposal in this Docket on the opening day of the expert witness evidentiary hearings, and the Commission took judicial notice of all filings in the Tax Docket. Tr. Vol. 5, p. 14.

On the first day of the evidentiary hearing, the Company presented its proposal to address the Tax Act. The Company Proposal was presented in this proceeding by witness De May. Tr. Vol. 4, pp. 423-24; Tr. Vol. 5, pp. 67-79; De May Rebuttal Ex. 5. The Company Proposal has three basic component parts, and the first two components reduce the Company's revenue requirement.

First, the Company Proposal implements an immediate reduction of approximately $211.5 million to the Company's revenue requirement to reflect collection of federal corporate income tax at the 21% rate instead of the 35% rate. Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues, Line 29; Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Line 1.

Second, the Company Proposal implements Federal EDIT flowback to customers, with the flowback timeframes varying based on the particular Federal EDIT bucket at issue:

- For protected Federal EDIT, the Company Proposal applies the Tax Act-prescribed IRS normalization rules, resulting in a reduction in revenue requirements of approximately $34.4 million annually or per year. Revised McManeus Stipulation Ex. 1 – Updated for Post-Hearing Issues, Line 30; Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Line 2.
- For unprotected Federal EDIT related to property, plant and equipment, the Proposal also applies the normalization rules, although, as all of the parties agree, application of those rules is not required by the Internal Revenue Code. The only modification, that results in a faster flowback, is that while the Company's analysis indicates that the average life of the flowback in the absence of the Tax Act would have been 25 years, the Proposal implements that flowback over 20 years. Tr. Vol. 5, pp. 78, 105. DEC maintained that this was done "for the sake of simplicity" (id. at 105.), and results in a reduction in revenue requirements of approximately $36.7 million annually or per year. Revised McManeus Stipulation Ex. 1 – Updated for Post-Hearing Issues, Line 33; Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Line 3.
- For unprotected Federal EDIT not related to property, plant and equipment, the Proposal implements flow back through a five-year decrement rider, with the five-year timeframe being used again "for the sake of simplicity." Tr. Vol. 5, p. 105. The reduction in revenue is approximately $39.6 million per year during the five years the rider is in effect. Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Line 7. Because these unprotected Federal EDIT are being flowed back to customers through a rider, that includes a return component, base rates must be adjusted correspondingly (as an increase) in the

amount of $15.1 million. Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Line 5.

Accordingly, the reduction in revenue requirements effected by these two components of the Company Proposal equals $307.1 million annually or per year. Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Lines 1-3, 5 and 7.

The third component of the Company Proposal mitigates, but does not eliminate, the negative cash flow impact of these reductions by increasing annual revenue requirements by $200 million. The Company Proposal (De May Rebuttal Ex. 5) did not originally identify specific means through which this could be accomplished, but did provide examples of accelerated regulatory asset amortization, and also suggested the alternative of collecting certain expenses (for example, the coal ash basin closure cost "run rate") on an accelerated basis.[48] As witness De May testified, in concept this component of the Company Proposal aims "to preserve the cash flow and credit quality, and we can skin that cat a few ways." Tr. Vol. 5, p. 87.

Combined, therefore, the three component parts of the Company Proposal net to a reduction in the Company's annual revenue requirement of almost $107 million. Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1. The Company Proposal implements an immediate reduction in rates to reflect the 21% Federal corporate income tax rate, but also, as witness De May testified, mitigates the impacts and "preserve[s] … [the Company's] credit quality ... to something that resembles pre-tax reform." Tr. Vol. 5, p. 82.

On cross-examination, Company witnesses Fountain and McManeus were questioned about the Company's income tax proposal. Witness McManeus acknowledged that ratepayers advanced the funds that constitute the Federal EDIT at issue. Tr. Vol. 6, p. 399. She also conceded that tax normalization laws do not dictate when unprotected PP&E Federal EDIT should be returned to ratepayers (unlike protected Federal EDIT). Tr. Vol. 6, p. 399. Witness McManeus further admitted that because unprotected Federal EDIT is not subject to tax normalization rules, the Commission has discretion as to the time period over which the funds will be returned to ratepayers. Tr. Vol. 8, p. 224. She agreed that due to the reduction in the tax rate, the Federal EDIT is no longer needed to cover the Company's taxes. Tr. Vol. 8, p. 224. Witness McManeus acknowledged that the $200 million in accelerated expenses would be included in the Company's revenue requirement. Tr. Vol. 8, p. 226. When asked to identify the specific assets and other items that the Company would include in the proposed $200 million acceleration, she could not identify anything specific, referring to the general options set forth in the proposal. Tr. Vol. 8, p. 230. Witness Fountain conceded that he could understand the positon of some customers who would like to have the benefits of the

[48] Kathy Sparrow, one of the public witnesses in the public witness hearing held in Charlotte on January 30, 2018, also suggested that tax reform gains and coal ash costs could offset against each other. Tr. Vol. 3, p. 95.

federal tax reform all flowed back immediately, but testified that the Company's proposal is balanced. Tr. Vol. 7, p. 94.

In response to Commission questions about the Company's income tax proposal, witness McManeus testified that the $200 million figure was provided by witness De May as an appropriate number to accomplish the objectives that he had in mind. The Company did not provide any specific numbers that comprise the $200 million. Tr. Vol. 9, p. 38. Witness Fountain could not identify any specific regulatory assets the Commission could select for accelerated amortization. Tr. Vol. 9, p. 90. Witness Fountain acknowledged that the Company is merely trying to achieve a particular financial metric for its cash flow. Tr. Vol. 9, p. 90.

On March 19, 2018, Public Staff witness Boswell filed her Second Supplemental Testimony. In addition to explaining the current differences between the Company's and the Public Staff's revenue requirement proposals and to refine the outside services adjustment, she addressed DEC's income tax proposal. She explained that while the Company has incorporated the known and measurable reduction in income tax expense associated with the decrease in the federal corporate income tax rate, the Company appears to have made the refunding of known and measurable tax dollars owed to ratepayers contingent upon increasing annual expenses by $200 million per year for an unknown number of years through the acceleration of depreciation for as yet unknown assets or through accelerating the amortization of costs associated with coal ash basin closures. Tr. Vol. 26, p. 634. She also noted that the Company has calculated the known and measurable refund of protected Federal EDIT based upon tax normalization rules. However, regarding unprotected Federal EDIT, she stated that the Company has proposed an amortization of approximately 82% of its unprotected Federal EDIT over 20 years, with the remaining 18% amortized over five years.

Thus, the Company's and the Public Staff's proposals differ as to: (1) the rate at which unprotected Federal EDIT should be flowed back to ratepayers; and (2) whether it is appropriate to increase the Company's revenue requirement by $200 million to accelerate depreciation of unknown and unspecified assets or legacy meters, or accelerated amortization of coal ash costs. Tr. Vol. 26, pp. 634-35. Witness Boswell noted that the Company does not dispute that the Commission has the discretion to flow back all of the unprotected Federal EDIT over any time period it finds appropriate. Tr. Vol. 26, p. 636. Company witness De May testified extensively regarding the impact implementation of the Tax Act could have on the Company's credit quality and the importance of maintaining the Company's current, high credit rating. Witness De May explained that as a result of the Tax Act, Duke Energy Corporation, the parent Company of DEC, was placed by Moody's on negative credit outlook. Tr. Vol. 4, p. 541. He explained that a negative outlook is different from a ratings downgrade. Witness De May stated that it is "like a yellow light, a warning" (id.), signaling to the investment community that a ratings downgrade could materialize in the next 12 to 18 months. Id. The January 2018 Moody's Report states that the Tax Act is "credit negative" for the utilities sector because of its impact upon cash flow, and that among the companies most negatively impacted is Duke Energy Corporation, the parent company of DEC.

January 2018 Moody's Report, pp. 1, 3. The Report specifically notes that the parent corporation's "consolidated cash flow credit metrics are currently weakly positioned and likely to be incrementally pressured by tax reform." Id. at 5.

While Moody's has not put DEC on negative credit outlook, as witness De May explained, "the risk to Duke Carolinas is not zero just because it was not named in the initial report." Tr. Vol. 4, p. 542. Witness De May testified that while DEC currently maintains "a very strong balance sheet," the Tax Act is biased toward the health of corporations, and because utilities are structured different than most corporations, the Tax Act impacts utilities negatively. Tr. Vol. 5, p. 82. As Moody's notes, "most utilities will attempt to manage any negative financial implications of tax reform through regulatory channels … [and that] actions taken by utilities will be incorporated into our credit analysis on a prospective basis." Moody's January 2018 Report, p. 3.

Moreover, witness De May elaborated, during cross-examination by counsel for CIGFUR III, on the negative impact of weakening the Company's balance sheet: "Duke Energy Carolinas' customers benefit from a strong utility company … [and] a weakening of the balance sheet is not in the customer's interest, and it does not support the Company's capital plan …." Tr. Vol. 4, pp. 436-37. He testified further, "[u]ltimately, adverse cash flow impacts also have an adverse impact upon customer rates – DE Carolinas' customers benefit through lower electricity rates when the Company has lower financing costs, greater access to capital, and more timely cash recovery of its investments." Id. at 88-89.

The Company has proposed a 20-year flowback of unprotected but property-related EDIT. The Public Staff has criticized this aspect of the Company Proposal on several grounds. First, Public Staff witness Boswell asserted that the Company has "artificially" created the class of unprotected property-related EDIT. Tr. Vol. 26, p. 636. Witness De May explained that the 20-year period in the Company Proposal is tied directly to the underlying assets that created the deferred tax balances that became Federal EDIT when the Tax Act dropped the corporate income tax rate to 21%. As witness De May testified:

> I would say that from a theory perspective, those excess deferred taxes actually have a life. When I described to you what happened in a single asset where we collect from customers before we pay the government and then we're paying the government, but not collecting from customers, that is something that is dealt with through normalization. But there's a life to that; there's a life cycle to that, and protected and unprotected property related deferred taxes are no different except for the fact that they come from two places in the Internal Revenue Code and the statute protects one and it doesn't the other.

Tr. Vol. 5, p. 78. Witness De May testified further in response to questions from Commissioner Brown-Bland that he trusted "firmly in the theory behind the flowback of excess deferred taxes over the life of the underlying assets" (id. at 102-03.), that the normalization concept underlying the 20-year flowback proposal was discussed at length in the GAO Report, and that "normalization exists for a reason …." Id. at 103. Witness De May testified that normalization balances the customer and Company interests; it protects the Company's cash flow and also protects the customer against rate volatility, because the deferred balance acts as an offset to rate base, and, therefore, a reduction in rates. Id. at 104.

Also, as both the GAO Report and witness De May noted, deferred taxes represent an interest-free loan from the government that the Company then used, at no cost to customers, to invest in its business. Tr. Vol. 5, pp. 72-73. Witness De May explained that by making these investments, customers saved capital costs by the Company using an interest-free loan from the government rather than investor-supplied capital. However, witness De May testified that because these funds have been invested there is not a readily available reserve pool from which the cash needed to flow back the EDIT can be drawn and the Company would have to enter into financings to flow back EDIT in two years as originally proposed by the Public Staff. Id. at 79. He explained that it helps avoid volatility in customer rates. Id. at 80. Witness De May stated that, "[i]f we flowback these excess deferred taxes instantly or over a two-year period, you would see a dramatic reduction in customer rates followed by a snapping back of rates" and then a faster growth in rates due to the higher rate base. Id.

The Public Staff also raised generational equity concerns in advocating for a shorter flowback time period. EDIT funds, it indicated, "rightfully belong to the ratepayers and should be returned to them as soon as reasonably possible." Tr. Vol. 26, p. 637. Witness De May responded, ". . . we have to think about how that balance got created." Tr. Vol. 5, p. 73. Witness De May noted that it was created because of tax deferral, and the funds so generated then were invested in the business. Id. The Company argued that normalization, or the gradual return of EDIT over the life of the capital asset being depreciated, actually fosters generational equity by spreading the depreciation benefit over that time period.

The Company asserted that the Public Staff's proposed 5-year flowback would negatively impact its credit metrics. Tr. Vol. 5, p. 86. DEC maintained that, in fact, Hinton Cross Examination Exhibit 1 indicates that the relevant FFO/Debt ratios for the Public Staff Proposal over the Company's five-year planning horizon would fall below the 25% threshold, which the most recent Moody's report on DEC warned could result in a possible downgrade. See Moody's October 2017 Report, p. 2.

Finally, the Public Staff criticized the Company Proposal on the basis that in the last major overhaul of the Tax Code in 1986, the Company proposed and the Commission accepted a 5-year flowback of unprotected EDIT. See Order Allowing Rates to Become Effective (Stipulated 1987 Order), dated December 4, 1987, filed in Docket Nos. M-100, Sub 113 and E-7, Sub 415.

The Company, however, noted some differences between the 1986 tax law and today's Tax Act. First, DEC asserted that the total amount of the North Carolina retail portion of unprotected Federal EDIT is approximately $953 million, and in 1987, the North Carolina retail portion of unprotected Federal EDIT was approximately $28 million. See

Application by Duke Power Company for Authority to Decrease Electric Rates and Charges (Stipulated 1987 Application), dated November 13, 1987, filed in Docket No. E-7, Sub 415. Also, as witness De May testified, the magnitude of the reduction in tax rates was smaller in 1986 – the reduction was from 46% to 34%, a 26% decrease, while today the reduction was from 35% to 21%, a 40% decrease. Tr. Vol. 4, p. 446. Finally, DEC argued that the general business environment was different as well. Witness De May testified that in 1986, the Company experienced 5-6% customer growth and today it is half of a percent. Id. at 448. See De May – Public Staff Cross-Examination Ex. 21, Slide 24. Witness De May also stated that the Company is "experiencing environmental challenges unlike anything we had in 1986." Tr. Vol. 4, p. 448.

According to DEC, another credit supportive measure is the third component of its Proposal, which mitigates the negative cash flow impact of Federal EDIT flowback by increasing revenue requirements by $200 million annually. The Public Staff indicated that it is "adamantly opposed" to this part of the Company Proposal. Tr. Vol. 26, p. 639. The Public Staff argued that adoption of this part of the proposal would "virtually" wipe out the "entire" benefit to customers. Id. The Company, however, has noted that customers will benefit under the Company Proposal by $107 million per year. Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1. This component of the Company Proposal provides for early collection of regulatory assets – that is, from the customer perspective, liabilities otherwise owed to DEC by customers. Tr. Vol. 4, p. 445. Witness De May explained that extinguishing these liabilities has a beneficial effect on the Company's cash flows, but also means that customers will pay less in the future. Id. DEC maintained that accelerated payment also reduces the carrying cost of those regulatory assets, again lowering customer charges. Moreover, the Company noted that the Moody's January 2018 Report forecasted this exact type of regulatory outcome, which Moody's predicts will be credit supportive as utilities work through regulatory channels to manage the negative financial implications of tax reform, stating: "For example, to offset a decline in cash flow, utilities could propose to regulators additional investments that benefit customers or accelerate recovery of regulatory assets." Moody's January 2018 Report, p. 3.

The AGO asserted in its post-hearing brief that as a result of recent reductions in the federal corporate income tax, DEC's costs are much lower going forward and it has accrued a large sum in federal deferred taxes that it no longer needs. The AGO argued that these cost reductions should be flowed through to ratepayers promptly. The AGO recommended that the Commission reject DEC's problematic proposals and approve utility rates that promptly flow through the benefits for customers. The AGO stated that it concurs with the testimony given on behalf of DEC's ratepayers, who advocate a prompt reduction in the Company's revenue requirement to account for the cost of service impact.

The AGO maintained that the extra $200 million increment sought by DEC should be rejected, because by deviating from the statutorily mandated ratemaking formula, DEC would establish rates that are inflated by design. The AGO asserted that fixing rates that are intended to over-collect revenues is contrary to the ratemaking formula in N.C. Gen. Stat. § 62-133(b) and (c), and violates key ratemaking principles. The AGO stated that the Commission's responsibility is to "fix such rates as shall be fair both to the public utilities and to the consumer." N.C. Gen. Stat. § 62-133(a). The AGO further stated that the statutory intent is that the Commission "fix rates as low as may be reasonably consistent" with Due Process constitutional considerations.[49] The AGO asserted that the burden of proof is on the utility to show that its proposed changes in rates are just and reasonable according to N.C. Gen. Stat. § 62-75; 62-134(c) and that DEC cannot meet that burden.

The AGO noted that Commission precedent and North Carolina case law support the prompt flow-through of tax reform benefits to utility ratepayers. The AGO noted that when Congress passed the Tax Reform Act of 1986, the Commission found that the significant reduction to the tax rate would "have an immediate and favorable impact on the cost of providing … public utility services to consumers in North Carolina," and concluded that "[i]t is incumbent upon this Commission to take the appropriate action as required so as to preserve and flow through to ratepayers, as a reduction to public utility rates, any and all cost savings realized in this regard which would otherwise accrue solely to the benefit of the stockholders." Order Initiating Investigation In the Matter of the Tax Reform Act of 1986, issued October 22, 1986 in Docket No. M-100, Sub 113, at 1. The AGO noted that, affirming the Commission's final decision in that proceeding, the North Carolina Supreme Court observed that the purpose of the Commission's proceeding in 1986 was to "take the effect of the reduction in tax rates and flow it through to the ratepayers." State ex rel. Utils. Comm'n v. Nantahala, 326 N.C. at 197, 388 S.E.2d at 122.

The AGO stated that, similarly, when the North Carolina legislature adopted tax reform in 2013, it intended for the benefits of reduced state income taxes to be flowed through to ratepayers as the tax changes occurred. See In the Matter of Implementation of House Bill 998 – An Act to Simplify the North Carolina Tax Structure and to Reduce Individual and Business Tax Rates in Docket No. M-100, Sub 138.

The AGO maintained that furthermore, although DEC has claimed that customers may be harmed by the reduction to its cash flow prompted by a reduction in rates, the evidence in support of that hypothetical position was not substantiated. The AGO stated that the Tech Customers witnesses Brown-Hruska and Strunk reviewed claims by DEC witness De May that the Company's funds from operations to debt (FFO/Debt) ratios would drop to the point that a downgrade would likely occur. The AGO stated that based on their review of the projected FFO/Debt ratios proffered by witness De May and the most recent credit assessment from Standard & Poors, they concluded that DEC's credit metrics would not be jeopardized by the elimination of the additional $200 million in cash flow. Tr. Vol. 26, p. 514.

The AGO noted that, rather, the Company's projections demonstrate that the Company is on track to maintain and even to exceed, after implementation of the Tax Act, FFO/Debt ratios in the range of 24 to 26 percent, which is the base case assumption

[49] State ex rel. Utils. Comm'n v. Duke Power Co., 285 N.C. 377, 388, 206 S.E.2d 269, 276 (1974) (Duke Power).

relied upon by S&P before the Tax Act became law. Consequently, the AGO recommended that the Commission reject DEC's request for a $200 million annual increase in its revenue requirement.

The AGO noted that another impact of the federal income tax rate reduction is that it prompts a large reduction in the amount of accumulated deferred income taxes that DEC has accrued. The AGO stated that DEC acknowledges that customers should benefit from the excess accumulation. The AGO stated that, nonetheless, DEC proposes to spread out the return of most of the excess over many years, so that its rates are not reduced as much as they would be if the excess is returned promptly.

The AGO stated that it supports a return of the excess deferred taxes as soon as possible, but in no event longer than the initial recommendation of the Public Staff to return the excess deferred income taxes over 2 years because ratepayers will benefit immediately from the use of the amounts they are owed. The AGO argued that DEC has not supported its claim that any harm will fall to customers by the prompt return of the funds, and it is time for DEC to stop relying on excess revenues or a loan from its customers to maintain the overly flush cash flow that was provided under former tax deferral policies. The AGO asserted that the alternative of not returning dollars to consumers who struggle to pay their bills, or to consumers who would use their money for different purposes if given the opportunity, results in an undue burden on ratepayers and communities in North Carolina.

CIGFUR III stated in its post-hearing brief that the Commission should reject DEC’s proposal to prolong the return of unprotected PP&E EDIT to ratepayers over a period of 20 years and should implement the Public Staff’s proposal to return all unprotected EDIT over a five-year period.

CIGFUR III stated that in the early years of a given capital asset, the utility collects more in tax expense from ratepayers than it pays out to the IRS due to the difference in accelerated depreciation for tax purposes and straight-line depreciation for ratemaking purposes; that situation reverses once the ratemaking depreciation expense begins to exceed the tax depreciation. CIGFUR III noted that assuming that tax rates stay constant, over the life of a capital asset, the total tax expense paid by the ratepayers to the utility should match the tax expense the utility pays in federal taxes. CIGFUR III maintained that as a result of the differences in depreciation timing and because tax funds are ratepayer supplied, in the early years of a given capital asset ratepayers provide the utility an interest-free loan, reflected as a credit to the utility’s ADIT liability account. CIGFUR III noted that due to the Tax Act, DEC’s future tax liabilities will not be as high as anticipated when DEC filed its general rate case in August 2017, and the amount by which DEC’s current ADIT balances exceed their future income tax liability because of the Tax Act are the EDIT at issue.

CIGFUR III stated that while certain EDIT have been designated by the IRS code as “protected” and are required to be normalized over the remaining life of the asset, the Commission has wide discretion in the timing and duration of the return of “unprotected”

EDIT. CIGFUR III recommended that the Commission conclude that unprotected EDIT should be promptly flowed back to ratepayers; however, the Company proposes to delay returning what it designates as unprotected PP&E EDIT, although it concedes that this category of EDIT is not subject to IRS tax normalization rules. CIGFUR III stated that it opposes delayed return of unprotected EDIT and supports the Public Staff's recommendation that the unprotected EDIT be returned to ratepayers over 5 years.

CIGFUR III argued that the tax normalization rules are very clear and either EDIT is protected, or it is not. CIGFUR III asserted that the EDIT that the Company designates as "PP&E-related" is still clearly unprotected; a fact conceded by the Company. CIGFUR III stated that the Company's assertion that it should only return this PP&E-related unprotected EDIT over the same period of time it would have paid the funds to the IRS had the tax law not been passed is not supportable by any logical accounting or ratemaking principle, and should not dictate this Commission's decision as to what is a reasonable amount of time within which to return these funds to ratepayers. CIGFUR III asserted that these funds rightfully belong to the ratepayers and should be returned to them as soon as reasonably possible.

CIGFUR III maintained that while DEC stated that the delayed refund of unprotected EDIT is needed to protect its FFO/Debt ratio and thus its credit metrics, it has failed to offer compelling evidence in support of this justification. CIGFUR III asserted that to the contrary, Public Staff witness Hinton testified and concluded that, "it is unlikely that spreading the EDIT over five years will result in a debt rating downgrade and it is reasonable and fair to Duke's ratepayers and the Company." Tr. Vol. 22, p 277. As such, CIGFUR III urged the Commission to adopt the Public Staff's proposal to return all unprotected EDIT over 5 years.

CIGFUR III also recommended that the Commission reject DEC's proposal to "smooth out rate volatility" by slowing the flowback of benefits to ratepayers by accelerating the depreciation of ill-defined assets amounting to $200 million per year. CIGFUR III noted that DEC has requested this $200 million annual increase to its revenue requirements to collect expenses related to AMR meters, coal-fired plants, or coal ash clean up on an accelerated basis; specifically, the Company contended that its requested $200 million annual increase in its revenue requirement is required to mitigate the negative cash flow impact of the revenue requirement reductions resulting from the Tax Act and protects the Company's pre-Tax Act credit quality. CIGFUR III contended that, however, to the contrary, witnesses Strunk and Brown-Hruska, testifying on behalf of the Tech Customers, contended that:

> [T]he projected FFO/Debt ratios, adjusted so as to eliminate the request for an additional $200 million in cash flow, do not jeopardize the Company's credit metrics. Rather, the Company's projections demonstrate that the Company is on track to maintain and even to exceed – <u>after implementation of the Tax Act</u> – FFO/Debt ratios in the range of 24 to 26 percent, which is the base case assumption relied upon by S&P <u>before the Tax Act became</u>

> law. Consequently, we recommend that the Commission reject DEC's request for a $200 million annual increase in its revenue requirement.

CIGFUR III Brief, pp. 23-24.

CIGFUR III stated that as a result of the analysis performed by the Tech Customers witnesses and the Company's failure to present compelling evidence of financial harm, it contends that DEC's request to increase its annual revenue requirement by $200 million is unnecessary and should be rejected.

CUCA argued in its post-hearing brief that DEC's rates should be adjusted to give customers full credit for the reduction in the Federal corporate income tax rate from 35% to 21% contained in the Tax Act. CUCA asserted that giving the customers the full benefit of a 100% flow through of this federal income tax reduction will help to soften the economic blow to consumers' budgets that will result from any rate increase approved by the Commission in this case. CUCA noted that DEC, however, argued that the benefits of the Tax Act should not be 100% flowed through to the customers right away and instead, the customers should be required to accept a delayed payment of some of the benefits of the tax reduction while DEC makes other uses of the customers' money.

CUCA asserted that the "math in this situation does not require a rocket scientist to solve": Federal income tax rates are reduced from 35% to 21% and the "gross up" that DEC requires to account for income taxes is significantly reduced. CUCA stated that if the effective tax rates (like any other item of expense) go down, it has to follow that the utility's revenue requirement also must go down. CUCA Brief, p. 15. CUCA argued that the revenue requirement impact of a reduction in the federal corporate income tax rate from 35% to 21% is a finite, calculable amount. CUCA asserted that customers should immediately receive, as soon as any new rates for DEC become effective, the full benefit of this tax reduction. CUCA opined that DEC should not be able to place a hold on what is, fundamentally, the ratepayers' money by any sort of delayed refund mechanism. CUCA maintained that such a delay puts ratepayers in the position of having to pay "phony" or "phantom" income taxes as a part of the overall utility revenue requirement. CUCA Brief, p. 15.

CUCA noted that DEC argued that, unless it could delay reducing rates by the full amount of the tax reduction, it would be forced into a position of having to borrow working capital funds and that its credit rating could be seriously undermined. CUCA noted that the Supplemental Testimony of the Tech Customers witnesses clearly refutes this argument. CUCA stated that the supplemental testimony shows that DEC will not experience any funding difficulties and will not incur any sort of erosion or damage to its credit rating.

CUCA asserted that to the extent the Commission allows DEC, as DEC has requested, to delay the full impact of the Tax Act tax reductions, then the customers and ratepayers are, in essence, being required to provide an interest free loan to the DEC stockholders. CUCA argued that if the Commission allows this, then the amounts of the

Tax Act tax refunds that are not immediately flowed through should bear interest, to be ultimately repaid to the customers, at an annual rate of not less than 10% of the value of the delayed refund during the time of such delay. CUCA stated that that is the only way in which the ratepayers can be made whole for the loan they would be forced to make to the DEC stockholders. CUCA stated that, in addition, if DEC is allowed to delay the full impact of the tax refund implemented by Congress and the President, this delay will tend to reduce the business, financial, and operating risks of DEC. CUCA argued that, therefore, in addition to the payment of interest, the Commission should reduce the rate of return on equity awarded to DEC because of the risk reduction.

The Justice Center et al. stated in their post-hearing brief that the recent changes to federal tax law give the Commission an opportunity to mitigate the impact of any rate increase on the Company's most vulnerable customers. The Justice Center et al. noted that DEC has collected a large pool of unprotected EDIT. The Justice Center et al. urged the Commission to direct $5 million of the EDIT to the Helping Home Fund, which provides efficiency upgrades to low-income customers, for each year of the period over which the EDIT is amortized to flow back to ratepayers. The Justice Center et al. argued that at the same time, the Commission should reject DEC's request to retain $200 million in ratepayer dollars per year as cash-flow protection for the Company.

The Justice Center et al. noted that at the Greensboro public hearing, the executive director of the NCCAA, Sharon Goodson, recommended that the Company contribute up to $5 million annually to the Fund. Tr. Vol. 2, pp. 21-22; Goodson Ex. 1. The Justice Center et al. asserted that a $5 million annual contribution from DEC's unprotected EDIT represents less than 14 percent of the total unprotected EDIT that will flow back to ratepayers, and a smaller percentage of the overall EDIT that is owed to ratepayers.

The Justice Center et al. maintained that there is precedent for using a regulatory liability for the benefit of customers to fund energy-efficiency investments for the utility's low-income customers. The Justice Center et al. noted that the Helping Home Fund itself was originally funded with $10 million of a $20 million regulatory liability from DEP held for the benefit of its North Carolina retail customers.

In addition, the Justice Center et al. stated that sound policy reasons support directing a meaningful portion of the unprotected EDIT for targeted investments in low-income energy efficiency, rather than simply flowing all of the funds to ratepayers through rebates or a decrement rider. The Justice Center et al. maintained that utility investments in energy efficiency help to alleviate high energy burdens faced by low-income households, particularly when those households are faced with rate increases. The Justice Center et al. argued that low-income households, racial minorities, renters, and low-income customers residing in multifamily buildings experience higher than average energy burdens, meaning that they pay a higher percentage of their income on energy bills than their counterparts. The Justice Center et al. asserted that the Southeast faces some of the highest energy burdens in the nation and that households with high energy burdens must face difficult trade-offs between paying utility bills and paying for other necessities such as food, prescriptions, transportation, and medical care.

Tr. Vol. 8, pp. 33-38. The Justice Center et al. also stated that low-income households are more likely than the average household to have older and less efficient appliances. The Justice Center et al. stated that by lowering energy costs during periods of high demand, and avoiding or deferring the need to build or upgrade expensive new power plants and transmission infrastructure, investments in energy efficiency also bring system-wide benefits that are shared by all customers. The Justice Center et al. stated that each dollar invested in energy efficiency yields up to four dollars in benefits for customers.

The Justice Center et al. noted that at the evidentiary hearing in this matter, DEC witness Fountain recognized that it would be appropriate for the Commission to direct a portion of the unprotected EDIT for the benefit of low-income customers. The Justice Center et al. stated that when asked whether the Company would object to allocating a portion of unprotected EDIT to the Helping Home Fund, witness Fountain agreed that the Commission could use a portion of the unprotected EDIT for low-income energy-efficiency measures: "the Tax Act is a tool that the Commission has before it that it can use to mitigate customers' rate impacts in a variety of different ways, and…there could be some considerations for low-income customers….it's a very useful tool for the Commission to be able to have." Tr. Vol. 7, p. 57. The Justice Center et al. stated that, moreover, witness Fountain agreed that there was precedent for using a regulatory liability held by the Company for the benefit of ratepayers to support the Helping Home Fund. Id. at 58. The Justice Center et al. noted that Commissioner Patterson asked witness Fountain whether the Helping Home Fund has been favorably received and whether DEC had considered making additional contributions to the Fund in the context of this general rate case. Tr. Vol. 9, pp. 111-12. The Justice Center et al. maintained that while witness Fountain praised the program, he acknowledged that the Company has made no commitment to further support the program from shareholder dollars or otherwise in this rate case.[50] Id. The Justice Center et al. stated that similarly, Commissioner Clodfelter and Chairman Finley urged DEC to consider additional ways to meet the needs of low-income customers, including consideration of the Ohio Percentage of Income Payment Plan and the Missouri "Dollar More" program. Tr. Vol. 9, pp. 97-98; 114-15.

The Justice Center et al. maintained that DEC's failure to offer any assistance to its low-income customers to mitigate the effects of its proposed increase in rates and charges should be relevant to the Commission's decision whether to grant any of those requested increases. See, e.g., Order Granting General Rate Increase, Docket No. E-2, Sub 1023, p. 82 (May 30, 2013) (finding that funding of low-income assistance programs "is a just and reasonable measure to mitigate the impact of the proposed rate increase on . . . low-income customers"). The Justice Center et al. noted that the potential impact of new rates on customers is a "critical consideration" in the Commission's determination on whether to accept those new rates. Cooper, 366 N.C. at 495, 739 S.E.2d at 548 (holding that the Commission must consider the impact of changing economic conditions on customers when determining return on equity for a public utility). The Justice Center

[50] On June 1, 2018, DEC made a shareholder-funded commitment of $4 million for programs including those to assist low-income customers.

et al. asserted that to the extent that the Commission grants any component of DEC's request for a rate increase, it would be reasonable to order the allocation of $5 million per year of DEC's unprotected property, plant, and equipment EDIT to the Helping Home Fund for as long as that EDIT is amortized to flow back to ratepayers.

Kroger asserted in its post-hearing brief that customers should receive the full benefit of the tax savings provided by the Tax Act. Kroger noted that the reduction in the corporate income tax rate per the Tax Act will reduce DEC's federal income tax expense for regulatory purposes and that this reduction in tax expense should directly reduce the revenue requirement in this case. Kroger stated that viewed in isolation, this single component of the change in tax law, i.e., the reduction in the tax rate from 35 percent to 21 percent, reduces DEC's revenue requirement by a significant amount.

Additionally, Kroger noted that the Tax Act has implications for DEC's ADIT. Kroger stated that DEC accumulates these deferred income taxes in the ADIT on its regulatory books in an amount equal to this anticipated future tax liability. Kroger asserted that now that the corporate income tax rate has been reduced by 40 percent, DEC's anticipated future tax liability has also decreased by a comparable amount. Kroger noted that as of January 1, 2018, when the new tax rates became effective, a substantial portion of the ADIT on DEC's books will be considered to be "<u>excess</u>" ADIT. Kroger asserted that this excess ADIT should be returned to customers.[51]

Kroger recommended that the Commission reduce the revenue requirement in an amount that provides customers with the full benefit of the tax savings provided by the Tax Act and that the Company's revenue requirement in this case should be adjusted to reflect the direct impact to its cost-of-service and excess ADIT should be credited to customers starting with the rate effective period in this general rate case.

NCLM noted in its post-hearing brief that its witness Brian W. Coughlan provided testimony that DEC's rates should be adjusted downward to account for the significantly lower corporate income tax rates that DEC will pay since the enactment of the Tax Act. Tr. Vol. 8, pp. 105-107. NCLM noted that its Settlement Agreement with DEC did not resolve the issues raised by NCLM as to adjusting all rates downward to account for the lower corporate income tax rates in the Tax Act. NCLM stated that DEC's unanticipated tax savings should be used to mitigate any rate increase.

NCLM stated that its witness Coughlan addressed this issue in his testimony to supplement the Commission's work in Docket No. M-100, Sub 148. Tr. Vol. 8, pp. 105-107. NCLM noted that witness Coughlan simply asserted that, "[t]he new tax cuts should be taken into account now. The new tax rates take effect before the new electric rates will take effect. If the new tax rates are not accounted for at this time, DEC will have significantly higher than expected and appropriate earnings, and DEC customers will pay unfairly high rates between now and the next rate case." <u>Id.</u> at 106. NCLM respectfully requested that the Commission allow rate payers to benefit from the tax cuts to the maximum extent possible in this docket.

[51] Direct Testimony of Kevin Higgins, pp. 6-7.

The Tech Customers asserted in their proposed order and post-hearing brief that the Commission is required in this general rate case to, among other things, account for the Company's operating expenses for the test year, taking into account "evidence … tending to show actual changes in costs". See, e.g., N.C. Gen. Stat. §§ 62-133(b)(3) and (c). The Tech Customers stated that given this requirement, the effects of the Tax Act as to the rates charged by the Company should be addressed in this general rate case rather than the separate, generic proceeding that the Commission has initiated in Docket No. M-100, Sub 148. The Tech Customers asserted that the Public Staff's proposal for return of EDIT best balances the need to return tax overcollections to ratepayers as promptly as possible with the appropriate regulatory goals of avoiding adverse rate impacts for ratepayers and allowing sufficient time for DEC to manage its cash flow so as to avoid negative impacts to its credit metrics.

Further, the Tech Customers maintained that DEC's proposal to offset the reduction in its revenue requirement resulting from the Tax Act with $200 million in accelerated depreciation expense is not sufficiently supported in the record and raises significant legal and practical concerns. The Tech Customers argued that a decline in revenues resulting from a change in federal tax law does not, by itself, support the adoption of offsetting revenue increases where those increases are not independently justified and supported.

The Tech Customers noted that given that the issue relating to the implementation of federal tax reform was introduced into this proceeding after the filing of testimony by the parties, the parties have addressed this issue through supplemental testimony, examination at hearing, and in post-hearing briefing.

The Tech Customers noted that they offered Supplemental Testimony of witnesses Strunk and Brown-Hruska. The Tech Customers witnesses evaluated the reasonableness of DEC's contention that a $200 million annual increase in spending was necessary to support its credit metrics. The Tech Customers stated that based on the projected FFO/Debt ratios offered by DEC witness De May and a review of the most recent credit assessment of Standard and Poor's, witnesses Strunk and Brown-Hruska found that DEC's projected FFO/Debt ratios, adjusted to eliminate the request for an additional $200 million in cash flow, do not jeopardize the Company's credit metrics. Tr. Vol. 26, p. 514. The Tech Customers stated that, instead, their analysis study shows that DEC is on track to maintain, or even exceed, its stated FFO/Debt ratio goal after implementation of federal tax reform. Id. The Tech Customers maintained that witnesses Strunk and Brown-Hruska also compared DEC's FFO/Debt ratio to those of comparable companies, including those in witness Hevert's proxy group, and found that DEC's ratios are in line with, or above, those of the comparable companies and that its FFO/Debt ratios are among the healthiest among the proxy group companies both on a current and projected basis. Id. at 516-517. Based on this analysis, the Tech Customers noted that their witnesses concluded that DEC's rationale for its proposal was inconsistent with the financial forecasts it has provided in its own exhibits and not necessary to protect its current credit standing. Id. at 519.

The Tech Customers stated that the Commission is required in this general rate case to, among other things, account for the Company's operating expenses for the test year taking into account "evidence . . . tending to show actual changes in costs." See, e.g., N.C. Gen. Stat. § 62-133(b)(3) and (c). The Tech Customers asserted that this statute suggests, if not mandates, that the Commission implement tax reform in this proceeding.

Further, the Tech Customers stated that they agree with the Public Staff's recommendations concerning EDIT. The Tech Customers stated that they do not find support in accounting or ratemaking principles for the distinction in unprotected EDIT advocated by DEC. The Tech Customers stated that the PP&E assets for which DEC seeks a 20-year amortization period, like other unprotected EDIT, are not subject to IRS normalization rules. The Tech Customers asserted that Congress intentionally excluded EDIT from unprotected assets from the treatment given to protected EDIT because the excluded assets do not have normal useful lives. The Tech Customers noted that DEC asserted that unprotected PP&E EDIT is similar in nature to protected EDIT (which is also related to PP&E) and therefore it is reasonable to flow it back over a similar period. Tr. Vol. 5, p. 78. However, the Tech Customers stated that they can discern no principled basis for distinguishing between the assets in the manner proposed by the Company and an examination of the specific assets in this category suggests that they include assets (e.g., casualty loss, depreciation lag, AFUDC debt, pension cost) with highly uncertain accounting lives. See DEC Response to Public Staff Data Request No. 155-3, filed March 22, 2018.

Moreover, the Tech Customers argued that 20 years is simply too long a period over which to return over-collected ratepayers' money, and DEC has offered no evidence suggesting otherwise. In this regard, the Tech Customers stated that they are sympathetic to the need to return tax over-collections as expeditiously as possible. See, e.g., Buckeye Pipe Line Co., 13 FERC ¶ 61267, 61594 (1980) ("Millions of the Americans who use [electricity] live in poverty or on very tight budgets. Those people are in no position to lend money to anybody. A state of affairs that compels them to supply . . . electric companies with long-term credit in amounts that may sometimes seem minuscule on a per capita basis to the affluent but that are almost always material to the poor and to those who are just getting by cannot be viewed complacently.").

The Tech Customers noted that DEC has also raised concerns about the impact of the EDIT flowback on its cash flow that it speculates could negatively impact its credit metrics. Tr. Vol. 5, pp. 67-83. While the Tech Customers acknowledged the concerns raised by DEC, as well as the benefits that ratepayers derive from the Company's strong credit profile, the Tech Customers recommended that the Commission conclude that DEC's evidence on this point is not compelling or convincing.

Moreover, the Tech Customers noted that the Company's concerns over cash flow and credit metrics are mitigated, to an extent, by the Public Staff's five-year flow back proposal that provides the Company with the benefit of removing the total amount of the unprotected EDIT credit from the rate base in the current case, which benefits the Company by increasing rates and thereby moderating any cash flow issues, to the extent they may arise. The Tech Customers asserted that the financing cost to the Company will be imposed ratably over the period that the EDIT is returned through the levelized rider.

Finally, the Tech Customers recommended that the Commission conclude that DEC's proposal to offset the reduction in its revenue requirement resulting from the Tax Act with $200 million in accelerated depreciation expense is not sufficiently supported in the record and raises significant legal and practical concerns. The Tech Customers maintained that a decline in revenues resulting from a change in federal tax law does not, by itself, support the adoption of offsetting revenue increases where those increases are not independently justified and supported. The Tech Customers asserted that aside from the desire to offset reductions resulting from the change in tax law, the Company has not offered any principled explanation of the need for accelerated depreciation nor has it offered any basis for applying special depreciation rates for particular assets. The Tech Customers noted that DEC does articulate concerns about adverse rate impacts on consumers, but the Tech Customers support a five-year return of EDIT that will help ameliorate adverse impacts resulting from the return of EDIT. Moreover, the Tech Customers maintained that as to DEC's credit metrics, record evidence suggests that DEC's projected FFO/Debt ratios, adjusted to eliminate the proposed additional $200 million in cash flow, will not jeopardize the Company's credit metrics. Tr. Vol. 26, p. 514. The Tech Customers stated that, instead, evidence suggests that DEC will be on track to maintain, or even exceed, its stated FFO/Debt ratio goal after implementation of federal tax reform without an annual $200 million revenue increase. Id.

In light of the parties' testimony and all of the evidence presented, the Commission finds and concludes that it is appropriate to: (1) recognize a $211,512,000 per year reduction in DEC's revenue requirement to reflect the current 21% Federal corporate income tax rate; (2) deny DEC's proposed $200 million per year credit metric mitigation measure; and (3) allow DEC to continue to maintain all EDIT related to the Tax Act in a regulatory liability account for three years or until its next general rate case, whichever is sooner, at which point it will be returned to DEC's customers with interest reflected at the overall weighted cost of capital approved in this case of 7.35%. The Commission concludes that this approach appropriately balances the interests of DEC and its ratepayers.

The evidence shows that there is some agreement between the parties regarding how to implement the effects of the Tax Act. The Company and the Public Staff agree upon the revenue requirement effect of the decrease in the corporate income tax rate, the repeal of the manufacturing tax deduction, and the elimination of bonus depreciation. No party disputes the amounts presented by the Company and the Public Staff regarding the impact of the Tax Act on these issues, and the Commission finds and concludes that the revenue requirement changes presented by the Company and the Public Staff related to these issues are appropriate and should be approved. This decision results in a $211,512,000 per year reduction in DEC's revenue requirement.

Further, the Commission gives great weight to the testimony of the Public Staff, the AGO, CIGFUR III, the Justice Center et al., Kroger, NCLM, and the Tech Customers that DEC's proposed $200 million per year credit metric mitigation measure is inappropriate and should be denied. Therefore, the Commission declines to allow the Company to include an additional $200 million in its annual revenue requirement for the purpose of offsetting the impacts of the Tax Act on DEC's revenue requirement.

The Commission agrees with the Public Staff that DEC's request amounts to essentially eliminating the benefit of the corporate income tax decrease on the Company's ongoing expenses. DEC's request for this extraordinary relief was presented in very vague and uncertain terms; the Company simply mentioned a few possible uses for the additional $200 million in annual revenue. None of the Company witnesses could even articulate the reason for the $200 million number, nor could they provide a breakdown of what that number represents, other than that witness De May felt the number to be appropriate. The Commission further agrees with the Tech Customers that a decline in the tax rate does not support the adoption of an offsetting revenue requirement increase that is not independently justified and supported. The Commission also agrees with the Tech Customers that adoption of the $200 million proposal would raise significant legal and practical concerns. Moreover, as noted by the Public Staff, the request was not time-limited; in theory, the additional $200 million in revenue requirement would equate to $1 billion after five years. Finally, the Commission finds and concludes that offsetting known and measurable reductions in taxes to be paid going forward against the recovery of unknown ongoing coal ash basin closure costs as ultimately proposed by DEC in its Post-Hearing Brief and Proposed Order in this docket in order to delay reflecting the current Federal corporate income tax rate in base rates constitutes inappropriate ratemaking.

The Commission finds that the $200 million in additional annual revenue requirement appears solely designed to arbitrarily inflate the Company's revenue requirement beyond the actual cost of service. The Company essentially seems to be telling ratepayers that they can receive the reduction in the tax rate, but they have to pay most of it back through accelerated depreciation expenses. The Commission rejects this proposal as arbitrary. The Commission is confident that the Company's management can navigate this situation without artificial and arbitrary adjustments to annual revenue requirement. The Commission concludes that the Company's request for an additional $200 million per year as a credit metric mitigation measure is not supported by the preponderance of the evidence and therefore is denied.

Finally, the Commission notes that DEC filed its rate case application in August 2017, four months before the enactment of the Tax Act. The Commission finds that it is appropriate to recognize this fact in rendering its final decision in this matter. The Tax Act is the most significant federal tax legislation since the 1986 Tax Act enacted some 30 years ago. Based on this fact and finding that the evidence presented by DEC concerning its credit metrics and a possible credit downgrade merit some weight, the Commission concludes that DEC shall maintain all of its EDIT in a regulatory liability account pending flow back of that liability to DEC's ratepayers with interest reflected at the overall weighted cost of capital approved in this case of 7.35% in three years or in DEC's next general rate case proceeding, whichever is sooner. If DEC has not filed an application for a general rate case proceeding by June 22, 2021, it shall file its proposal by that date to flow back to its ratepayers both the protected and the unprotected EDIT generated due to the Tax Act. The federal EDIT flowback proposal should include all workpapers that support the proposed calculations. The Public Staff is specifically requested to file comments on the proposal by no later than July 22, 2021. Other parties also may file comments on the proposal by no later than July 22, 2021.

The Commission notes that in the generic rulemaking proceeding established by the Commission to address the recent changes in the State corporate income tax rate (Docket No. M-100, Sub 138), the Commission concluded that EDIT for all utilities, as appropriate, were to be held in a deferred tax regulatory liability account until they could be amortized as reductions to income tax expense for ratemaking purposes in each utility's next general rate case proceeding. The Commission stated that it agreed with PSNC Energy's comments in that docket that recognizing the amortization of the EDIT in the next general rate case of a utility would provide for certainty as to the amount to be amortized instead of having to base the flow-back calculation on an estimate. In that proceeding, no party objected to that option of handling the EDIT. In addition, the Commission noted in its May 13, 2014 Order in the generic proceeding that both Carolina Water Service, Inc. of North Carolina (CWSNC) and Aqua had had open rate case proceedings at the time the generic State tax docket was initiated. A rate order was issued in CWSNC's rate case docket on March 10, 2014, and a rate order was issued in Aqua's rate case docket on May 2, 2014. The Commission concluded in the May 13, 2014 Order that the expense piece of the State corporate income tax rate change was reflected in the rates established in the CWSNC and Aqua open rate case proceedings, but that CWSNC and Aqua needed to adhere to the findings on State EDIT outlined in the May 13, 2014 Order. The May 13, 2014 Order concluded for the State EDIT that each utility was to hold the State EDIT in a deferred tax regulatory liability account until they could be amortized as reductions to income tax expense for ratemaking purposes in each utility's next general rate case proceeding. The Commission's decision herein is reasonably consistent with the treatment of CWSNC and Aqua in the generic State corporate income tax proceeding.

Further, the Commission notes that this process used in Docket No. M-100, Sub 138 has worked well and customers received or are receiving EDIT related to the State corporate income tax rate changes. In fact, in this proceeding, DEC and the Public Staff stipulated to begin returning (four years after the Commission's State EDIT decision in the May 13, 2014 Order in the generic rulemaking docket) to DEC's customers the State EDIT through a four year decrement rider.

In addition, the Commission notes that in the Commission's 1986 federal corporate income tax law change generic rulemaking proceeding (Docket No. M-100, Sub 113), the Commission concluded in its October 20, 1987 Order to Require Filing of Tariffs to Reduce Rates and Refund Plans to Effect Flow Through of Tax Savings for Those Regulated Companies not covered by Specific Orders on This Matter (1987 Order), as follows:

> [t]hat the appropriate amortization of accumulated excess deferred income taxes will be considered in each company's next general rate case or such other proceeding as the Commission may determine to be appropriate. Any additional amounts relating to the adjustment that should have been made by the company for the flowback of excess deferred income taxes shall be placed in a deferred account and should ultimately be refunded to ratepayers with interest.

1987 Order. Although this conclusion was reached in a generic rulemaking proceeding, the Commission concludes that the fact that DEC had already filed its rate case application before the enactment of the Tax Act in this instant proceeding, it is appropriate to follow this same process for returning Federal EDIT to DEC's ratepayers.

However, the Commission, in its discretion, concludes that it is appropriate in this case to set a time limit for DEC to retain all of the EDIT generated due to the Tax Act. The Commission concludes that it is preferable to address this EDIT in a rate case proceeding; but due to the sheer magnitude of the EDIT that in total is approximately $2.14 billion, the Commission finds that DEC must begin the process to flow back the EDIT to ratepayers no later than three years from the date of this Order (or sooner if DEC files a rate case in less than three years). Therefore, the Commission concludes that if DEC has not filed an application for a general rate case proceeding by June 22, 2021, it shall file its proposal by that date to flow back to its ratepayers both the protected and the unprotected EDIT generated due to the Tax Act. The federal EDIT flowback proposal should include all workpapers that support the proposed calculations. The Public Staff is specifically requested to file comments on the proposal by no later than July 22, 2021. Other parties also may file comments on the proposal by no later than July 22, 2021.

In conclusion, the Commission finds it appropriate to: (1) recognize a $211,512,000 per year reduction in DEC's revenue requirement to reflect the current 21% Federal corporate income tax rate; (2) deny DEC's proposed $200 million per year credit metric mitigation measure; and (3) allow DEC to continue to maintain all EDIT related to the Tax Act in a regulatory liability account for three years or until its next general rate case whichever is sooner at which point it will be returned to DEC's customers with interest reflected at the overall weighted cost of capital approved in this case of 7.35%. The Commission concludes that this approach appropriately balances the interests of DEC and its ratepayers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 59-64

The evidence supporting these findings of fact and conclusions is found in the Company's verified Application, DEC's Petition for an Order Approving a Job Retention Rider (JRR), filed on August 14, 2017, in E-7 Sub 1152 (JRR Petition), the testimony of Company witness Pirro, the testimony of Public Staff witness McLawhorn, the testimony of other witnesses, the exhibits of witness Pirro, and the entire record in this proceeding. The Commission takes judicial notice of the Company's Initial and Reply Comments filed in Docket No. E-100, Sub 73 where the Company outlined the conditions that led to the loss of industrial jobs and where the Commission issued establishing guidelines on December 8, 2015. (JTR Order)

In its Petition, DEC requests approval of its JRR, a five-year pilot program for industrial customers that is intended to curtail further loss of industrial jobs in DEC's service territory. Petition, at p. 1. The Commission acknowledged the JRR's goal to stem further loss of industry, industrial production and industrial jobs in DEC's service territory as an important policy goal for North Carolina when it adopted the Guidelines for Job Retention Tariffs in Docket No. E-100, Sub 73. Petition at p. 3. Company witness Pirro testified in support of the Company's proposed JRR. Witness Pirro explained that the JRR will benefit ratepayers by retaining North Carolina jobs and strengthening local economies thereby aiding the commercial and residential markets. Tr. Vol. 19, p. 95. Since 2014, 50 manufacturing facilities served by Duke Energy have ceased operation in North Carolina. Id. at 78, 90. Witness Pirro states that the Company's IRP Update, filed on September 1, 2017 in Docket No. E-100, Sub 147, demonstrates the continuing struggles of manufacturing in North Carolina. Tr. Vol. 19, p. 90. He testifies that "[t]he Plan shows a steady decline in the number of industrial customers receiving electric service and our expectation [is] that even by 2023 industrial sales will still be below actual pre-recession sales realized in 2007." Id.

Witness Pirro also explained the eligibility requirements for the proposed JRR. Customers that use 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 or a finished product would be eligible for the Company's proposed JRR. Id. at 90-91. Furthermore, in order to qualify for JRR, industrial customers must show that they (i) have or are considering the ability to shift production from their facilities to facilities in other states or countries; (ii) are considering a need to reduce the employment level at their facilities due in whole or in part to the impact of electricity cost; (iii) intend to reduce or are presently evaluating reduction of production levels or load due in whole or in part to the impact of electricity cost; or (iv) have load that is otherwise at risk of loss. Petition at p. 5. Additionally, eligible customers must have an aggregate electrical load of 3,000 kW or greater, in addition to other conditions described in the Petition and proposed JRR. Tr. Vol. 19, p. 91.

In its Petition, the Company does not seek recovery of the revenue reduction resulting from implementation of the JRR at this time, but instead requests deferral accounting with interest on the amount in excess of the $4.5 million that the Company will absorb on a one-time basis. Petition at p. 3.

CUCA witness O'Donnell testified in support of the Company's proposed JRR. Witness O'Donnell testified that if DEC continues to lose industrial load, the fixed costs of operating the DEC system will be shifted to the remaining customers in an amount even greater than the average 0.74% cited in DEC's Petition. Tr. Vol. 18, pp. 54-55. For example, witness O'Donnell calculated that if the Company's manufacturing load completely eroded, the remaining customers' rates would increase by over 16% annually.

Id. at 55. He concluded that it would be much less harmful to residential customers to pay a 0.74% increase for five years than to have a permanent 16.22% increase. Id.

CIGFUR III witness Phillips also testified in support of the Company's proposed JRR. Witness Phillips testified that the Company's proposed JRR follows the Guidelines for Job Retention Tariffs issued by this Commission on December 8, 2015 in Docket E-100, Sub 73, and that the proposed JRR is in the public interest, and recommended that the Commission approve it. Tr. Vol. 26, p. 280. Witness Phillips testified that his review of DEC's historic and projected growth in customers indicated that within the 2007 to 2032 timeframe, the Company will see residential customers increase by 32.2%, commercial customers increase by 23.3%, and industrial customers decrease by 28.6%. Id. at 281. Witness Phillips testified that the proposed JRR will benefit all customers because "[i]f industrial load is lost, DEC would need to recover a larger portion of fixed costs from its remaining customers, resulting in higher electric rates for these customers." Id. at 282. Therefore, preserving jobs and industrial load through the Company's proposed JRR will strengthen the economy and keep electric rates lower for DEC's non-industrial customers. Id. Witness Phillips also testified that the Commission's guidelines in Docket No. E-100, Sub 73 do not exclude pipeline customers that are also important to the North Carolina economy. Id. at 283. Therefore, he testified that it would be unreasonable to impose restrictions on the Company's proposed JRR that exclude those customers. Id. at 284.

While the Public Staff is supportive of the JRR and believes that it is in the public interest, witness McLawhorn expressed several concerns regarding the proposed rider. Tr. Vol. 20, pp. 141-46. First, witness McLawhorn expressed concern with the availability of the rider to customers involved in the "transportation or preservation of a raw material of a finished product," which is understood to include gas pipeline customers. Id. at 141-42. He noted that pipelines are different than other industrial manufacturing facilities in that pipelines are fixed investments that are not easily relocated to another area, and unlike other industrial manufacturers, pipelines do not produce a finished product. Id. at 142. He recommended this disputed phrase be eliminated from the availability section of Rider JRR-1. Second, he argued that there are no specific criteria designated for use by the Public Staff to evaluate customer employment and financial records to aid in evaluating an applicant's justification for seeking the JRR thus depriving the Public Staff of the ability to verify the truthfulness of the information. Id. at 142-44. He also opposed the Company's request for deferral accounting of the revenue loss and the Company's proposal for sharing the discount between the Company's shareholders and ratepayers. Id. at 146. Lastly, witness McLawhorn recommended that the requirement that the discounted revenue must be used to retain jobs in North Carolina be more prevalently displayed in the Application form and that the language in the compliance filing clearly identify the length of the JRR from initial approval. Id. at 145-46.

Despite these concerns, the Public Staff generally supports the Company's proposed JRR, concluding that the rate reduction it provides for industrial customers would "assist them in maintaining jobs and load in North Carolina." Id. at 139-40. Witness McLawhorn testified that the Company's proposed JRR complies with the Commission's

Guidelines for Job Retention Tariffs set forth in its December 8, 2015 order in Docket No. E-100, Sub 73. Tr. Vol. 20, pp. 134-38. Witness McLawhorn also testified that the proposed JRR is not unduly discriminatory because it is designed to reach the largest industrial customers, which impact other commercial and residential customer classes. Tr. Vol. 20, p. 138. Witness McLawhorn further stated that the proposed JRR "provides for a balancing of benefits and costs between those customers eligible for [JRR] and those that will bear the reduction in revenue that result from implementation of the rider." Id. at 139. Lastly, witness McLawhorn recommended that the impact of the rate discount be recovered from all retail ratepayers, including the customers eligible for the rate discount. Id. at 147.

Commercial Group witnesses Chriss and Rosa testified in opposition to the Company's proposed JRR. Witnesses Chriss and Rosa state that the proposed JRR fails to comply with Commission guidelines by limiting applicability to a subset of industrial customers and the rigor of verifying customer attestations is unclear. Tr. Vol. 26, p. 547. Witnesses Chriss and Rosa further request that if the JRR is approved, that it be extended to non-industrials that also provide jobs and have aggregate loads of 3,000 kW or greater. Id.

In its post-hearing Brief, Commercial Group continues to advocate a denial of the JRR. However, Commercial Group recognizes that the Commission approved a more limited JRR for DEP in DEP's rate case which included five safeguards, which the Commercial Group contends should be adopted in this case if approved. Commercial Group submits that the JRR would violate N.C. Gen. Stat. § 62-140(a) because it would unjustly discriminate among customers having an aggregate load of at least 3 MW based solely on whether the customer is an industrial customer. Commercial Group contends that this is a return to the Standard Industrial Classification (SIC) code distinctions that the Commission found discriminatory and rejected in prior proceedings. Commercial Group states that the Commission stated its concern in its final Order in DEC's 2011 rate case, Docket E-7 Sub 989, regarding the reasonableness and fairness of maintaining a rate differential based largely on labels such as the SIC codes. Commercial Group quotes N.C. Gen. Stat. § 62-140(a), and states that the legal standard is not whether a public utility can subject a customer to an unreasonable prejudice or disadvantage if doing so would be an advantage to other customers or the utility. Rather, the legal standard is that the public utility cannot grant any unreasonable preference or subject any person to any unreasonable prejudice or disadvantage. Further, Commercial Group contends that industrial customers are not a separate class of service because both industrial and commercial customers are members of the same OPT-V class, and that many non-industrial ratepayers in these classes have an aggregate load of at least 3 MW. According to Commercial Group, where the JRR's only distinguishing characteristic is industrial status, the JRR remains as unlawful and unduly discriminatory as the preference for OPT industrial customers that the Commission previously rejected, and, therefore, the JRR as proposed should be rejected as well.

In addition, Commercial Group states that the proposed JRR definitions and parameters that DEC selected provide only an illusion of being reasonable criteria for determining which customers should receive a rate subsidy. As an example, Commercial Group contends that the applicant could simply state that it has at some time in the past thought about obtaining the ability to move a portion of its operations out of state, but the applicant need not presently have such ability, presently plan to move operations out of state, nor be in such financial condition that jobs would be lost but for a JRR subsidy. Commercial Group further notes that the applicant does not need to maintain existing levels of employment, but instead chooses a level of employment that it states it will maintain, even if the level is lower than its present level.

Commercial Group notes that DEC witness Hevert gave convincing testimony that economic conditions in North Carolina have improved substantially since DEC's last rate case in 2013, and since the Commission adopted job retention guidelines in 2015. The unemployment rate in North Carolina and DEC's service territory has fallen substantially during these periods. Tr. Vol. 4, pp. 161, 165. Further, the correlation between the drop in unemployment in North Carolina and more broadly across the United States has been very high. Id. at 165. Moreover, DEC industrial customers already receive competitive rates that are below the national average and below the average in the Atlantic South region.

Commercial Group questions whether there will be a means to assess the effectiveness of the JRR. Commercial Group cites the testimony of Public Staff witness McLawhorn regarding the report that DEC will be required to file, and states that the report will not provide any reliable, independently verifiable information to determine the success or failure of the JRR. Based on the uncertainty of verifiable results from the JRR, Commercial Groups requests that the Commission should require the same safeguards that it required of DEP for its JRR in DEP's most recent rate case.

Company witness Pirro's rebuttal testimony responded to the concerns raised by other witnesses related the Company's proposed JRR. Witness Pirro agreed with the Public Staff's concern regarding difficulty evaluating customer financial and employment records. Tr. Vol. 19, p. 92. To address this concern, witness Pirro explained that DEC will impose a requirement that an officer of the customer sign the application and the signature be notarized. Id. Witness Pirro also noted that the guidelines don't require a demonstration of financial distress, but the discounted revenue must contribute to job retention in North Carolina. Id.

Additionally, witness Pirro testified regarding the inclusion of customers involved in the "transportation or preservation of a raw material of a finished product", that this language was included to allow the JRR to apply primarily to gas pipeline customers. Id. at 92. He stated that pipeline customers have expressed concerns with electricity costs and have requested rate relief to aid in their North Carolina operations. Id. DEC believes that it is reasonable to include this type of customer with manufacturing facilities when applying the JRR. Id.

Witness Pirro further testified that deferral accounting was requested because the timing and magnitude of the revenue reduction is unclear. Id. at 93. "The use of deferral accounting allows the Company to assess the true impact of the rider and seek recovery at a later date when revenues are more certain." Id. at 93-94. Witness Pirro also disagreed with witness McLawhorn's recommendation that the Company's shareholders absorb $4.5 million every year the rider is in effect. Id. at 95. Witness Pirro testified that the JRR will benefit ratepayers by retaining North Carolina jobs and strengthening local economies thereby aiding the commercial and residential markets. Id. While the Company's shareholders are willing to absorb a portion of the revenue reduction in the first year to implement the program, a requirement that shareholders absorb this cost in subsequent years would deprive the Company of a reasonable opportunity to recover its just and reasonable costs. Id.

Lastly, Witness Pirro agreed with witness McLawhorn's requested two changes to the application form and tariff. Id. at 93. He explained that the Company does not oppose the relocation of the statement regarding the discounted revenue being used to retain jobs in North Carolina to a more prevalent location in the Application. Id. The Company also does not object to more clearly identifying that the Rider terminate and no longer be available for service 5 years from the effective date of the Rider. Id.

In the Stipulation, the Company and the Public Staff agreed that "the Company's proposed Job Retention Rider generally complies with the Commission's guidelines adopted in Docket No. E-100, Sub 73, but two issues remain to be decided upon by the Commission: (1) whether companies involved in the transportation or preservation of a raw material or a finished product (e.g., pipeline customers) should qualify; and (2) how or if the Job Retention Rider should be funded after the expiration of the initial year's $4.5 million shareholder contribution." Stipulation, § II. c.

Except for the two unresolved issues stated above, the Stipulating Parties have agreed to the proposed JRR as described by witness Pirro in his rebuttal testimony, and further agreed that JRR revenue credits shall be recovered through a JRR Recovery Rider (JRRR) from all retail customers concurrent with JRR implementation, which is anticipated to occur approximately six months following the Commission's decision. Id. at 11, 13. The Stipulation provides that JRR and JRRR revenues shall be reported to the Commission annually and the JRRR shall be reviewed and will be subject to adjustment annually coincident with the September fuel adjustment to match anticipated recovery revenues and true-up any past over-or under-recovery. Id. at 13. Additionally, due to the uncertain date of implementation, compliance tariffs shall be filed prior to implementation of the JRRR and customers shall be notified by bill insert or message upon implementation. Id.

Company witness Pirro filed testimony and exhibits in support of the Stipulation. In his settlement supporting testimony, he explains that the recovery rate under the JRRR is set at $0.00041 per kWh to recover the first year of impact, less the $4.5 million absorbed by the Company, reduced by 10% for application lag. Tr. Vol. 19, pp. 107-08. Witness Pirro further testified that the JRRR is intended to keep the Company revenue neutral with respect to the JRR, other than the one-time $4.5 million contribution from shareholders, over the 5-year pilot period, and, if needed, a final true-up shall be applicable upon termination of JRR. Id. at 108.

The Commission finds and concludes that the Company's proposed JRR as modified by this Order is just and reasonable to all parties based on all of the evidence presented. The Commission finds that the continued loss of industrial jobs in DEC's service area will have a detrimental effect on the State. The Commission views the Company's proposed JRR as an effort to retain industrial jobs in North Carolina and concludes that implementation of the rider is in the public interest. As with other economic development tariffs previously approved by this Commission, approval of the JRR is based in part on an evaluation of the expected economic benefits resulting from the tariff. The Commission has considered the economic impact of the continuing decline of the North Carolina industrial base as well as the impact of the recovery rider on non-participating ratepayers, and concludes that the JRR strikes the appropriate balance between the two. The Commission concludes that by limiting the availability of the JRR to industrial customers, the Company has minimized the effect on non-participants while assisting the group of customers that are most in need of assistance. To further minimize the impact to non-participants and to achieve the goal of the JRR in the most cost-effective manner, the Commission shall limit the JRR to a one-year pilot, with the option of renewal for one additional year upon a showing that the JRR is achieving the intended objectives. Requiring the Company to show the Commission the effectiveness of the JRR in the rider proceeding removes any concerns expressed by the Commercial Group regarding measurement and verification. This reduction in the number of years for the pilot to one-year with the opportunity for a second year allows the Commission and the parties to assess the health of industrial sector as a whole after one year on the JRR and if an additional year would be in the public interest. In addition to the reduction of the pilot to one year, with the opportunity for a second year, the Commission determines that additional changes to the JRR are necessary for proper measurement and verification. First, the Company shall require the Customer to maintain an employment level of 90 percent of the its employees, with the number of employees determined by an average of its employment level over the twelve months prior to the filing of the Application and Agreement for the Job Retention Rider. The application shall state the specific number of employees and verify that this number represents 90 percent of the monthly average over the past twelve months. Second, the Customer shall submit in writing to DEC no later than March 1, and quarterly thereafter, a report verifying the employment level at the Customer's facility(s) receiving the Job Retention Rider credits. Third, if the Customer does not maintain the stated employee level, the Customer shall be removed from the tariff pursuant to the language in the proposed application and shall be required to refund the amount of benefits received under the JRR. DEC shall change the application language accordingly. The Commission has considered the arguments for expanding the JRR made by Commercial Group witnesses Chriss and Rosa, and concludes that expanding the JRR to other customer classes would place too large a burden on non-participants and would be unreasonable.

Furthermore, the Commission concludes that limiting the availability of the JRR to only industrial customers is not unreasonably discriminatory. Rather, it is based on a reasonable difference between customer classes, and the discount offered to participants under the JRR as compared to the amount of rider recovery on non-participants bears a reasonable proportion to the difference between the customer classes. See State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, 348 N.C. 452, 468, 500 S.E.2d 693, 704 (1998). Based on the evidence presented, the Commission finds that industrial customers' sales have been flat or declining since the recession, while residential and commercial sales are growing. Furthermore, a $0.003227 per kWh reduction in rates for participating industrials as compared to an increase in rates for the average retail customer of approximately $0.000539 per kWh per month under the JRR is proportionate to differences between these customer classes and reasonable given the economic and rate benefits of retaining industrial customers on DEC's system.

The Commission concludes that the JRR, with the modifications established in this Order, is in accordance with the requirements and guidelines the Commission previously established. In the JRT Order, the Commission directed utilities to "craft eligibility requirements that are narrowly tailored to meet the intended goals of maintaining jobs in the most economically efficient manner." Although the disputed phrase that allows for the eligibility for pipeline companies was included in the JRT Order as a possible example of eligibility criteria, the Commission is not persuaded that the eligibility criteria proposed by the Company is sufficiently narrow to ensure that the JRR will maintain jobs in the most efficient manner. Pipelines, which cannot relocate, are sufficiently different from other industrial customers and should be excluded from eligibility in the JRR. The disputed phrase "or the transportation or preservation of a raw material of a finished product" should be removed from the eligibility criteria.

The Commission further concludes that the customer attestations regarding certain eligibility requirements for the JRR, as modified by this order, are reasonable and adequate. Based upon the practical considerations of managing eligibility and how eligibility for certain rates is verified in other contexts, such as the opt-out process for DSM/EE rates, the Commission concludes that the Company's proposed method for verifying eligibility for the JRR is reasonable.

Commercial Group states that it does not take issue with the Commission's gradual approach to class revenue allocation, except if the Commission grants the proposed JRR. In that event, according to Commercial Group, the Commission should use any such reduction to move each customer class closer to its respective cost of service. The Commission does not agree with Commercial Group's position. The approval of the JRR does not eviscerate the principle of gradualism in reaching rate of return equilibrium among the customer classes. Further, the rate designs approved herein and the approval of the JRR will result in just and reasonable rates.

Finally, the Commission notes that the proposed JRR is a limited-term pilot, which will allow the Commission and the Company to follow the customers on the tariff and to consider whether the tariff meets its objectives of job retention and the related economic benefits. If it does not, then the JRR will not be continued beyond its one-year term. Except as modified by this order, the Commission finds that it is reasonable for DEC to implement JRR and JRRR as proposed in the Stipulation and Pirro Settlement Exhibit 1.

The Company, as well as ratepayers, benefit from the retention of industrial jobs, and the load related to the retention of the industrial jobs. In addition to the testimony in this case, this fact is further justified by the Company's indication in Docket No. E-100, Sub 73 that it was considering funding all or a portion of a JRT and provided comments on the necessary requirements for measurement and verification under the scenario of a fully Company-funded JRT. To achieve just and reasonable rates, if the pilot program is extended to a second year, it is appropriate for the Company to contribute to the JRR at the same level as year one. Therefore, the Company's recovery should be reduced by the amount of $4.5 million if the Commission determines in the rider proceeding that the JRR pilot program should be extended to a second year.

The Commission, therefore, concludes that the proposed JRR, as modified by this Order, is in the public interest, is not discriminatory and is consistent with the Commission's holding that "approval of a JRT is a matter of sound ratemaking policy to address the undisputed decline in industrial sales in North Carolina." Order Adopting Guidelines for Job Retention Tariffs in Docket No. E-100, Sub 73, at 22. If the JRR is extended an additional year and at the end of the second year the Company determines there is still a need for the JRR, nothing in this order prevents the Company for filing for a new JRR based upon the economic circumstances at that time.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 65-68

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the record in Docket No. E-7 Sub 1110, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

In Docket No. E-7, Sub 1103, DEC requested to defer its costs of complying with the Coal Ash Management Act (CAMA) and the EPA's Coal Combustion Residual Rule (CCR Rule, collectively CAMA) and notified the Commission that it had established an Asset Retirement Obligation (ARO).

In its March 15, 2017 comments in Docket No. E-7, Sub 1103, the Public Staff supported the Company's deferral request, provided that ratemaking treatment for the deferred amount would be determined in the next base rate case:

> In this particular case, the Public Staff believes that the non-capital costs and depreciation expense related to compliance with state and federal requirements cited in the Companies' petition generally satisfy the criteria for deferral for regulatory accounting (but not necessarily ratemaking) purposes. First, they are adequately extraordinary in both type of expenditure and in magnitude to justify consideration for deferral. Second, the effect of not deferring the expenses on the Companies' respective earned returns on common equity would be significant.

Initial Comments of the Public Staff, at p. 6.

In the present docket, DEC witness McManeus noted that the Company had petitioned in Docket Nos. E-2, Sub 1103, and E-7, Sub 1110, for approval to defer certain costs incurred to comply with environmental requirements for Coal Combustion Residuals (CCR or coal ash). Tr. Vol. 6, p. 239. While various parties opposed recovery in rates of some of the coal ash costs, that is a separate issue from the deferral request. The deferral request was generally unopposed, and the Commission finds and concludes that deferral in a regulatory asset for previously incurred coal ash environmental costs is consistent with the Commission's criteria for deferrals and reasonable in the circumstances of this case.

In the present docket, Public Staff witness Maness indicated that the Public Staff continues to believe that prudently incurred CCR expenditures should be allowed to be deferred for regulatory accounting purposes. Witness Maness made several adjustments and with regard to the addition of a return on deferred coal ash expenditures from December 2017 through April 2018, DEC agreed with this adjustment (Tr. Vol. 6, p. 314), and it was not opposed by other witnesses. The Commission notes that new rates will not be effective by May 1, 2018, as might have been expected at the time of the filing of witness Maness' testimony; therefore, the Commission finds it appropriate and reasonable to extend the accrual of this return until the effective date of rates approved in this proceeding. Based on the foregoing, the Commission finds and concludes that a return based on the net-of-tax overall weighted cost of capital authorized in DEC's last general rate case should be added to the amount of deferred coal ash costs are approved in this Order for recovery in rates, and that the return should be applied through the effective date of the rates approved in this proceeding.

Additionally, as recommended by the Public Staff, the Commission concludes that use of the 2018 federal income tax rate of 21% is appropriate to calculate the 2018 portion of the carrying costs. With respect to Public Staff witness Maness' adjustment regarding mid-month cash-flow convention, DEC witness McManeus accepted this adjustment (Tr. Vol. 6, p. 314), and no other witness opposed it. The Commission finds and concludes that the mid-month convention for calculation of the return is reasonable and appropriate. Additionally, as recommended by the Public Staff, the Commission concludes that compounding of the carrying costs should take place at the beginning, rather than the end, of January of each year.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 69-72

The evidence supporting these findings and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony of the public witnesses, and the testimony and exhibits of the following expert witnesses: DEC witnesses Fountain, McManeus, Kerin, Wells, Wright, De May, Hager, and Doss; Public Staff witnesses Junis, Garrett, Moore, Lucas, Boswell, and Maness; AGO witness Wittliff; CUCA witness O'Donnell; and Sierra Club witness Quarles.

The public witness testimony and expert witness testimony and exhibits regarding DEC's CCR costs are voluminous. The Commission has carefully considered all of the evidence and the record as a whole. However, the Commission has not attempted to recount every statement of every witnesses. Rather, the following is a complete summary of the evidence.

Likewise, the Commission has read and fully considered the parties' post-hearing briefs. However, the Commission has not in this order expressly addressed every contention advanced or authority cited in the briefs.

Based upon the evidence addressed below and in the exercise of its expert judgment and discretion, the Commission determines that a management penalty of approximately $70 million should be assessed for DEC's mismanagement of its CCR activities undertaken through the end of the test year as extended for reasons set forth hereafter.

Coal-fired power plants have played a predominant role in electricity generation by DEC throughout its history, and the Company is dependent upon coal-fired generation today. With coal-fired generation comes a by-product – coal ash, also known as coal combustion residuals, or CCRs. At least since the 1950s, standard industry practice, particularly in the Southeastern United States, has been reliance on coal ash basins. Such basins were constructed and used at all of the Company's coal-fired generating units.

The United States Environmental Protection Agency (EPA) has studied CCRs and their proper management and handling since the 1980s, but the agency only began moving forward on comprehensive regulation of CCRs less than ten years ago. In 2010, the EPA issued proposed rules regarding CCRs. EPA's final rule – the Coal Combustion Residuals Rule (CCR Rule) – was promulgated on April 17, 2015. North Carolina also enacted specific statutory requirements for coal ash management in CAMA, which became effective in 2014 and was amended in 2016. The CCR Rule and CAMA introduced new requirements for the management of coal ash. DEC, of course, must comply with these new requirements, which mandate closure of the Company's coal ash basins. Mandated closure triggers Generally Accepted Accounting Principles (GAAP) provisions relating to the retirement of long-lived tangible assets, and specifically triggers the requirement that the Company account for compliance costs through ARO accounting. The Company, as required by GAAP, established an ARO with respect to its coal ash basins, and, in accordance with the Commission's orders in Docket No. E-7, Sub 723, deferred the impacts of its GAAP-mandated ARO accounting. The Company now seeks recovery of the coal ash basin closure costs incurred to date in connection with CCR Rule and/or CAMA compliance, along with such costs it anticipates will be incurred annually on an ongoing basis. The Company's proposal has three component parts:

- First, DEC seeks recovery of the actual coal ash basin closure costs it incurred from January 1, 2015 through December 31, 2017. On a North Carolina retail jurisdiction basis, these costs amount to $566.8 million.[52] McManeus Rebuttal Ex. 3, pp. 36-37. The Company proposes further that, rather than recovering 100% of these already incurred costs immediately, it recover them over a five-year amortization period, and it seeks a return on the unamortized balance.

- Second, DEC seeks to recover on an ongoing basis $201.3 million per year in annual coal ash basin closure spend. This amount is based upon the NC retail jurisdiction portion of the test year (2016) coal ash basin closure expense incurred by the Company.
- Third, DEC seeks permission to establish a regulatory asset/liability and defer to this account the NC retail portion of annual costs that are over or under the costs established in connection with the Company's request that it be permitted to recover in rates on an ongoing basis its actual test year coal ash basin closure costs – i.e., the amount over or under $201.3 million, if the Company's proposal as detailed above is approved by the Commission. In addition, the costs incurred from January 1, 2018 through the date new rates set in this proceeding are effective would also be deferred to this account. The deferred amounts (including a return) would be brought into rates and recovered through future rate cases.

The Commission, as it has in prior rate orders, provides a review of the applicable legal principles, to provide a framework for the application of those principles to the facts of this particular case. See, e.g., 2013 DEC Rate Order, pp. 23-28 (in Duke Energy Carolinas 2013 Rate Case, Commission provided an extensive review of the "governing principles" regarding rate of return). For purposes of assessing the Company's coal ash basin closure cost recovery proposal, the applicable principles include (1) the general cost recovery framework and the role of the revenue requirement in that framework; (2) principles underlying "reasonable and prudent" costs; (3) principles underlying the concept of "used and useful," and (4) a discussion of the burden of proof, and, in particular, presumptions and the distinction between the burden of production (borne by Intervenors) and the ultimate burden of persuasion (borne by the Company).

In the recently-decided DEP rate case (Docket No. E-2, Sub 1142, the 2018 DEP Rate Case, or 2018 DEP Case), the Commission's decision summarized cost recovery based upon these principles, and found that for cost recovery the utility must prove that the costs it seeks to recover are "(1) 'known and measurable'; (2) 'reasonable and prudent'; and (3) 'used and useful' in the provision of service to customers." 2018 DEP Rate Order, p. 143. The same standard applies in this case.

The arguments raised by Intervenors in this docket challenge the inclusion of the Company's coal ash basin closure costs in rates because the costs are not "reasonable and prudent" and "used and useful," or on the theory that cost recovery should be shared by both the shareholders and ratepayers.

[52] This amount excludes any fines, penalties and other unrecoverable costs incurred by the Company. See Tr. Vol. 6, p. 259.

Summary of the Evidence

A. Company Direct Case Overview and Costs Sought for Recovery

In his direct testimony, Company witness Fountain testified that DEC is requesting recovery of ash basin closure compliance costs incurred in the period from January 1, 2015 through November 30, 2017. Witness Fountain explained that the Company has removed costs related to its response to the Dan River release and is not requesting their recovery for them. Tr. Vol. 6, p. 174. Witness Fountain also testified on direct that, based on actual coal ash expenses incurred during the 2016 test year, DEC is seeking recovery of ongoing ash basin closure compliance spend of $201 million per year, with any difference from future spend being deferred until a future base rate case. He stated that including this revenue requirement will provide a measure of predictability to customers of future coal ash expense rate drivers. Id. at 174.

Company witness McManeus testified that Adjustment No. 18 to the Company's operating revenues and expenses amortizes the actual deferred costs incurred through December 31, 2017, in connection with compliance with federal and state environmental requirements related to CCRs, pursuant to DEC's petition in Docket Nos. E-2, Sub 1103 and E-7, Sub 1110 for authority to defer such costs in a regulatory asset account, over a five-year period. She explained that while the costs to comply with CAMA and the CCR Rule are largely duplicative, the Company has determined a small portion of the costs to be specific to CAMA, unique to North Carolina and appropriate for direct assignment to North Carolina. She stated that in the deferral calculation, for CAMA-specific costs, the adjustment separates out the portion allocable to the wholesale jurisdiction and directly assigns the retail portion to North Carolina retail. She stated that these costs were based on actuals at the end of the test period, updated through November 30, 2017.[53] The Company proposes to defer these costs over a five-year period and to earn a net of tax return on the unamortized balance. Witness McManeus testified that the expected deferred balance, based on total system spend on these costs during this period, plus applying allocation factors and incorporating the return on the deferred costs, is $524.0 million.[54] Witness McManeus clarified the Company seeks no recovery for fines, penalties, or costs of which DEC has agreed to forego in the deferral. Tr. Vol. 6, pp. 259-60, 279-80, 288-89, 297, 343.

Witness McManeus testified that Adjustment 19 increases O&M to reflect the expected ongoing annual level of expenses DEC will incur in connection with coal ash compliance costs represents the amount in ongoing annual coal ash basin closure expense (sometimes referred to in this Order as "ongoing compliance costs"). She explained that this number – $201.3 million on a North Carolina retail basis – is based upon actual test year (2016) spend, and stated that the Company is also requesting

[53] These costs were later updated to actual costs through December 31, 2017, and the deferred balance including return computed as of April 30, 2018. McManeus Rebuttal Ex. 3, pp. 36-37.

[54] This amount has been adjusted to $566.8 million based on the estimated deferral balance at April 30, 2018. McManeus Rebuttal Ex. 3, pp. 36-37.

permission to establish a regulatory asset/liability and defer to this account the North Carolina retail portion of annual costs over or under the amount established in this proceeding. She explained that this will ensure that the Company only recovers from customers its actual level of spending related to coal ash. She also clarified that no fines, penalties, or costs of which DEC has agreed to forego recovery are included in this adjustment. Tr. Vol. 6, pp. 260-61, 279-80, 288-89.

B. Company Direct Case: Coal Ash Overview

Company witness Kerin described his management role with the Ash Basin Strategic Action Team (ABSAT), the umbrella organization created for Duke Energy companies to address the laws, regulations, and orders concerning the management of CCRs. Witness Kerin discussed how, during his work on the ABSAT team, he spent approximately 3,000 hours working exclusively on CCR issues, familiarizing himself with state and federal regulations dealing with CCR and historical industry practices and standards used to comply with such regulations. He described how he interviewed legacy employees who worked at, and with, coal combustion generating units and CCR handling sites, and reviewed historical company documents dealing with those facilities and sites in order to gain an understanding of how CCR handling standards inside and outside of the Company developed over time. Witness Kerin also described how he toured and inspected every CCR basin in Duke Energy's North and South Carolina jurisdictions, as well as CCR sites at Duke's Midwest sites, Dominion, AEP, and TVA. He detailed how he developed CCR evaluations for Duke Energy's CCR sites, and an industry peer group to discuss CCR issues generally, which continues to meet semi-annually. Witness Kerin concluded that during his time on the ABSAT team, he gained an understanding and knowledge of coal ash management practices at utilities across the country. Tr. Vol. 14, pp. 96-97.

Witness Kerin provided a detailed discussion of DEC's coal ash management history and practices and the new obligations imposed on the Company by the CCR Rule and CAMA. He explained that CCRs are by-products produced from the electricity production process lifecycle – the burning of coal – at coal-fired generation plants and include fly ash, bottom ash, boiler slag, and flue gas desulfurization (FGD) material. He stated that environmental regulations related to CCR management have evolved significantly over time, affecting how the Company has operated its coal-fired plants in compliance with those obligations. He maintained that at each step in the environmental regulatory evolution process, DEC was in line with industry standards and maintained that DEC reasonably and prudently managed CCRs and its coal ash basins. He explained that since its last rate case, DEC has become subject to both federal and state regulations that require it to take significant action to close its ash basins. Tr. Vol. 14, pp. 99-112.

Witness Kerin testified that since the early 1900s, DEC has disposed of CCRs in compliance with then current regulations and industry practices. Until the 1950s, CCRs were either emitted through, in the case of fly ash, smokestacks or, in the case of bottom ash, manually removed the ash from boilers and stored it in landfills. Since that time, the industry transitioned to a water sluice to remove ash from boilers, and to clean the electrostatic precipitators, preventing ash from being emitted through the smokestacks. This effluent, as well as FGD blowdown, was then diverted to ash basins, of which DEC has 17 in the Carolinas. In other words, in many cases, ash basins were actually created or relied upon to effectuate prior environmental regulations. In the mid-1970s, the enactment of the Clean Air Act and its subsequent amendment in the 1990s required electric utilities to capture more CCRs through the use of electrostatic precipitators (ESP) or bag houses and FGD blowdown. Tr. Vol. 14, pp. 99-112.

Witness Kerin provided a detailed history of coal ash regulation. He testified that the Clean Water Act of 1972 and the subsequent creation of the National Pollutant Discharge Elimination System (NPDES) permitting system, made wet ash handling and ash basins the primary lawful and effective way to meet CCR needs and environmental requirements from 1974 until 2015. Tr. Vol. 14, pp. 100, 106-09.

Witness Kerin testified that, in June 2010, the EPA proposed national minimum criteria to regulate the disposal of CCRs and the operation and closure of active CCR landfills and existing and inactive CCR surface impoundments. He stated that, approximately five years later in April 2015, EPA published the final CCR Rule in the Federal Register. He explained that the CCR Rule established national minimum criteria for CCR landfills and surface impoundments, which result in different impacts at each CCR unit, depending on site-specific factors, and testified to the exact nature of those criteria. He stated that the CCR Rule also contains requirements for how and when CCR basins must be closed, and that it provides for closure either by cap-in-place or removal of the ash. He noted that as stated in the CCR Rule, the EPA considers CCRs to be a non-hazardous solid waste. In 2014, North Carolina enacted CAMA, which requires that all ash basins in the State be closed, either through excavation or via the cap-in-place method. He explained further that CAMA requires closure of all ash basins in North Carolina, with the closure option (excavate or cap-in-place) and deadline driven by a prioritization risk ranking classification process. Witness Kerin noted that, in many respects, CAMA mirrors the federal CCR Rule. He stated that all of DEC's ash basins must be closed under one or both of these programs. Tr. Vol. 14, pp. 100, 115-26.

He also stated that the Company has begun the process of closing, or submitting plans to close, its ash basins in accordance with the program with the most limiting requirements. Tr. Vol. 14, p. 100. Witness Kerin also testified that coal-powered electric generation has since ceased at four of the eight coal-fired DEC generating facilities with ash basins, including the Dan River, Buck, Riverbend, and W.S. Lee plants. Id. at 103.

Witness Kerin also noted that in addition to the CCR Rule and CAMA, DEC is also subject to other CCR-related obligations that result from state environmental regulatory oversight under existing rules and regulations. For DEC, in South Carolina, there is one Consent Agreement with the South Carolina Department of Health and Environment (SCDHEC) applicable to ash management at the W.S. Lee plant. The W.S. Lee Consent Agreement, between DEC and SCDHEC, requires ash excavation of the Inactive Ash Basin, the Ash Fill Area, and any other areas where ash may have potentially migrated from these sites. Tr. Vol. 14, p. 127.

Witness Kerin testified that the CCR Compliance Requirements—CAMA, the CCR Rule, and other consent and/or settlement agreements and orders concerning CCR management and disposal—represent new regulatory requirements that have significantly changed the operation and life cycle of the on-site ash basins and landfills. Id. at 115. He noted that there is a great deal of duplication and interaction between federal rule, state law and agency action and that many of the actions Duke Energy will take will serve multiple compliance purposes. He explained that many actions and draft rules applicable to many utilities, not just Duke Energy, were already being developed prior to 2014, and that the Company is now in another wave of evolution in environmental regulation pertaining to ash. He stated that in response to these new requirements addressing CCR disposal activities, the Company is adding dry fly ash, bottom ash, and FGD blowdown handling systems to operating coal-fired plants that are not already so equipped. He also stated that the Company is modifying all active and decommissioned plants to divert storm water and low-volume wastewater away from the basins. He testified that, accordingly, the Company is requesting recovery of the incremental compliance costs related to coal ash pond closures incurred starting in 2015 through November 30, 2017, and recovery of ongoing compliance costs. He maintained that both these incurred and ongoing compliance costs are reasonable, prudent, and cost effective given the individual facts and circumstances at each power plant and ash basin site at issue. He maintained further that each of the Company's historical and ongoing CCR compliance costs is reasonable, prudent, and cost effective given the individual facts and circumstances at each power plant and ash basin site at issue. Tr. Vol. 14, pp. 100-01.

Witness Kerin stated that ash removal has been initiated at several DEC stations, including the Dan River and Riverbend Plants. He stated that excavation plans were developed to systematically prepare for executing this work, including the identification of any necessary permits and approvals. These excavation plans were submitted to the applicable state regulatory body, SCDHEC or DEQ, prior to beginning ash excavations. As the CCR Rule and CAMA lead to ash basin closure, preparations are required to transition the coal-fired generating sites for this outcome. Operating coal-fired power plants in the Carolinas require plant modifications to fully transition to dry ash handling in order to cease sluice flow to the ash basins. All coal-fired power plants, even those retired, require some level of modification to cease all flows to the ash basins, such as storm water or low volume waste water, and may require construction of a new retention pond. These modification activities are planned and are now being executed. Tr. Vol. 14, p. 132.

Witness Kerin described the closure plans and site analysis and removal plans developed by Duke Energy to physically close the ash basins, noting that these plans are technically informed by the structural stability of the impoundments, the potential for adverse impacts from external events such as 100-year floods, the groundwater and/or surface water impacts identified in the Closure Study Analysis, and the groundwater corrective actions required in the Corrective Action Plans. Ash basins can be closed by excavation, with the ash permanently stored in a CCR landfill or used in a beneficial way such as a structural fill or for cementitious purposes. Ash basins can also be closed by capping the CCR in place. Tr. Vol. 14, pp. 132-33.

Witness Kerin also maintained that the Company's CAMA closure plans will meet the national standards set forth by the CCR Rule as well as the more specific requirements determined by the North Carolina Department of Environmental Quality (DEQ) under the CAMA regulatory process. He explained that the state-mandated closure plans are reviewed and approved by SCDHEC in South Carolina and DEQ in North Carolina. During this review and approval process, these state regulatory agencies could impose additional restrictions, limitations, requirements, and/or actions to close the ash basins. Other specific compliance plans will be developed and implemented to meet the various requirements and timelines of CAMA and the CCR Rule, such as the fugitive dust control plans, which were required under Section 257.80 of the CCR Rule by October 19, 2015. As a second example, run-on and run-off control system plans were developed and implemented by October 19, 2016, for CCR landfills pursuant to Section 257.81 of the CCR Rule. Compliance plans will continue to be developed and implemented as required by the CCR Rule and CAMA. Tr. Vol. 14, p. 133.

Company witness Kerin testified that in Exhibits 10 and 11 to his testimony, he broke the ash pond closure costs already incurred or expected to be incurred prior to November 30, 2017, down into their core components and described the plants to which these costs apply. In detailing these costs, he also provided narrative summaries as to why, in his view, these costs were incurred and why the compliance actions which led to those costs were the most reasonable and cost-effective options given the applicable facts and circumstances. He maintained that these exhibits, coupled with the balance of his testimony and exhibits, demonstrate that these costs are reasonable and prudent. Tr. Vol. 14, p. 135.

Company witness Kerin maintained that DEC's historical handling of CCRs was reasonable, prudent, and consistent with industry standards over time. This demonstrates that nothing that DEC has done historically is causing the Company to incur any unjustified costs today to comply with post-2015 CCR regulations. Tr. Vol. 14, p. 135. Company witness Kerin explained that, in the preamble to the CCR Rule, EPA details that in 2012 alone, over 470 coal-fired electric generating facilities burned over 800 million tons of coal, generating approximately 110 million tons of CCRs in 47 states and Puerto Rico. In 2012, approximately 40% of the CCRs generated were beneficially used, with the remaining 60% disposed in CCR surface impoundments. Of that 60%, approximately 80% was stored in on-site basins and landfills. Across the United States, CCR disposal currently occurs at over 310 active on-site landfills, averaging over 120 acres in size with an average depth of 40 feet, and at over 375 active on-site surface impoundments. Stated differently, according to witness Kerin, the Company is re-using (selling) and storing CCRs in the same manner and at approximately the same percentages as the coal-fired utility industry's national averages. Duke Energy's practices have been and continue to be consistent with those of the industry. Similar to the industry, DEC has on-site CCR landfills that are actively receiving production fly ash, and some bottom ash, at specific coal-fired generating sites, including the Allen, Belews Creek, Cliffside, and Marshall Plants in the Carolinas. Also similar to the industry, DEC has active ash basins still receiving bottom ash, and some fly ash, at specific coal-fired generating sites, including the Allen, Belews Creek, Cliffside, and Marshall Plants in the Carolinas. Witness Kerin maintained that the ash handling practices for ash basins and ash landfills in the Carolinas are consistent with the applicable regulatory requirements that were in effect during the history of these CCR units. Tr. Vol. 14, pp. 113-14.

Witness Kerin also maintained that DEC's CCR storage and handling practices are consistent with the practices of other Duke Energy affiliates and Duke Energy peer utilities. He explained that the Company's CCR storage and handling practices are consistent across the Duke Energy fleet, including coal generation located in Florida and in the Midwest. Duke Energy as it currently exists today has been formed over the years through the mergers of several utilities with independently operated coal fired generation, including the Cinergy Corporation in 2006 and Progress Energy, Inc. in 2012. Indeed, going further back in time, Progress Energy, Inc. was created in 2000 from the merger of legacy utilities CP&L and Florida Power Corporation (FPC). Similarly, Cinergy Corporation was created in 1994 by the merger of legacy utilities Public Service Indiana (PSI) and Cincinnati Gas & Electric Company (CG&E). Yet, the historical and current CCR handling and use of CCR basins is consistent across all of these legacy companies that make up Duke Energy Corporation today, and consistent with the industry. Tr. Vol. 14, p. 114.

At the hearing, in response to questions from counsel for the Sierra Club regarding reports on ash disposal from the 1970s and 1980s, witness Kerin clarified that DEC did not build any new basins after 1982, when the last basin was constructed at Buck, and that any other disposal areas constructed by the Company would have been undertaken pursuant to permit by the DEQ or its predecessor. Tr. Vol. 14, pp. 180-84. He also testified that, in his opinion, there would not be increased cost associated with the schedule of activities contained in the draft Special Order by Consent (SOC) resolving a DEQ Notice of Violation with regard to the Allen, Marshall, and Cliffside plants that would not otherwise have been incurred, and clarified that cap-in-place costs are based on acreage size, not volume of ash in the basin. Id. at 213-18.

In his direct testimony, Company witness Wright noted that coal ash use and disposal has been studied by the EPA since the mid-1980s. After several studies and some limited regulatory standards, on May 22, 2000, the EPA determined the need to regulate coal combustion wastes under Subtitle D of the Resource Conservation and Recovery Act (RCRA). He noted that these types of expenses have been routinely recovered as a cost of service and included in rate cases including the reasonable costs associated with operating, maintaining and upgrading environmental equipment. The cost recovery for these rate-based environmental costs also usually included a return. Tr. Vol. 12, pp. 130-31.

C. Company Direct: Cost Recovery Overview

Witness Wright also testified that in part as a response to an accident at a surface impoundment at Tennessee Valley Authority's (TVA) Kingston Fossil Plant in Harriman, Tennessee, the EPA published in the Federal Register proposed new coal ash disposal regulations for CCRs. The proposed regulations specifically referenced the TVA incident as a major reason for the proposed rule, and discussed several other coal ash incidents that led to the promulgation of the rule. Witness Wright maintained that, because the EPA's proposed rule's publication date precedes the February 2, 2014 coal ash release accident at the Dan River Steam Station (Dan River), the Dan River accident was not mentioned in the EPA's proposed rule, nor could it have been, as a reason for establishing the rule. He also noted that EPA's finalized CCR Rule, signed on December 19, 2014 and published in the Federal Register (FR) on April 17, 2015, did reference the Dan River accident, but it did not indicate that the accident modified the proposed rule. Tr. Vol. 12, pp. 131-32.

Witness Wright further explained that in August 2014, after the EPA's proposed coal ash regulations were published but prior to their finalization, the State of North Carolina adopted CAMA. He noted that while EPA and CAMA rules are similar in many respects, "largely duplicative," DEC must ensure that its coal ash disposal methods meet the standards established in both regulations as well as any other state agency requirements. Tr. Vol. 12, p. 132.

Witness Wright maintained that recoverable costs, as they relate to electric utility expenditures in North Carolina, are costs that are reasonable and that are prudently incurred in the provision of safe, reliable electric service to a utility's customers. He argued that N.C. Gen. Stat. § 62-133(b) embodies this principle. He maintained that because environmental compliance costs are a necessary cost of providing electric service, these types of costs – and a return on those costs if deferred over time – are recoverable in rates. He also maintained that environmental compliance costs are similar to other costs that a utility might spend in producing and delivering power. He asserted that the Company incurs costs in compliance with environmental laws and regulations, similar to other costs necessary for the generation of electric power, and that these coal ash disposal costs are like nuclear decommissioning costs or coal plant retirement costs which have long been deemed recoverable for utilities across the country, including DEC. Tr. Vol. 12, p. 123.

Witness Wright noted that the Commission has allowed the recovery of costs related to environmental expenditures. Citing to witness Kerin's lengthy discussion of the numerous investments the Company has made over time in compliance with historical coal ash and other environmental regulations, he asserted that in his experience these types of costs, including the reasonable costs associated with operating, maintaining and upgrading environmental equipment, plus a return, have been routinely recovered as a cost of service through general rate cases, whether as capital or ongoing operation and maintenance expense or some combination thereof. Tr. Vol. 12, pp. 127-29.

Witness Wright testified further that utilities are not allowed to recover environmental fines or penalties, or costs incurred from the actions causing such penalties. He stated his understanding that none have been requested in this case. He also asserted that it is important, however, to make sure that the costs underlying or directly causing such fines or penalties be separated from prudently incurred, ongoing costs. For example, he offered, if a generating plant received a fine, that fine should not be recoverable. The fact that a fine was given, however, does not mean that the ongoing, prudently-incurred costs necessary to produce generation should be disallowed. Tr. Vol.12, p. 130.

Witness Wright further asserted that the new federal coal ash standards did not result from the Dan River spill. He noted that the final rule only mentions the Dan River accident, and that there is no clear evidence in the final rule that the Dan River accident changed or modified the EPA's proposed rule. He asserted that both the proposed rule and the final rule addressed the need for imposing corrective action at inactive facilities, and asserted that in promulgating the CCR Rule, the EPA cited hundreds of potential risks or incidents with ash ponds similar to Dan River that, in part, led to the adoption of the Rule. Based on this analysis along with the timing of the CCR Rule, he opined that the Dan River accident did not change the CCR regulations, although it probably added support for the EPA's proposals. Tr. Vol. 12, pp. 132-34.

Witness Wright also maintained that, in terms of timing, the new state CAMA coal ash standards did result from the Dan River spill, but in terms of the substance of the standards adopted there is not necessarily a connection. He opined that the Dan River spill helped prompt the North Carolina General Assembly to examine the State's and national coal ash disposal policies and regulations, and that out of that legislative investigation came CAMA. He noted that some four years prior to Dan River, the EPA had proposed and was close to finalizing its new CCR regulations, which in his opinion helped inform the State's legislative leaders regarding the language contained in CAMA. He noted that the proposed CCR regulation also strongly encouraged the states to adopt at least the federal minimum criteria in their solid waste management plans. Therefore, he concluded, that the North Carolina Legislature and/or the State's DEQ would likely have taken steps to adopt coal ash regulations shortly after the CCR Rule was finalized in 2015. He concluded that the timing of CAMA was influenced by the Dan River accident, but also expressed his belief that, even without the Dan River accident, the State would likely have adopted some new coal ash disposal standards similar to CAMA in the 2015 timeframe in response to the CCR rules. He stated that, regardless, the Company must comply with both the federal and state coal ash disposal standards. Tr. Vol. 12, pp. 134-36.

In his direct testimony, Company witness Wright testified that, in his opinion, the coal ash disposal costs that DEC seeks to recover in this case are "used and useful" utility cost. Tr. Vol. 12, p. 144. He explained that DEC's coal ash disposal sites have always been used and useful as part of the coal-fired generation production process. He noted that N.C. Gen. Stat. § 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." Id. He testified that, therefore, to be recoverable and/or included in rate base, the cost must be both reasonable and incurred for property that is used and useful in providing service to customers. He stated that 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 at the time, thereby rendering the disposal sites for this coal ash, for which costs DEC seeks recovery in this case, "used and useful" in providing electric service. Id. at 144-45. He stated that this is supported by the Commission's conclusions in the 2016 Dominion rate case, where the Commission determined that because current CCR repositories are and have served their purpose of storing CCRs for many years, they have been used and useful for ratepayers, and that such storage facilities will continue to be used and useful until the CCRs are moved to a permanent repository, or they are capped and closed. Id. at 145-46.

Witness Wright also noted with respect to the Commission's Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions in Docket No. E-22, Sub 532 (Dec. 22, 2016) (2016 DNCP Rate Order) that, in that case, the Commission addressed the exact issue of the recovery of coal ash disposal costs that is at issue in this proceeding. In addition to the decision that prior coal ash disposal assets were used and useful, he noted that in that order the Commission and Public Staff concluded that Dominion's historical response to coal ash disposal was consistent with industry practice at the time and that these costs were reasonable and prudent. Second, they found that Dominion's test year coal ash disposal expenses incurred in compliance with the newer coal ash disposal regulations were likewise reasonable and prudent. Finally, he noted that, similar to what DEC is requesting in this rate case, the 2016 DNCP Rate Order also allows Dominion to establish an ARO to defer additional coal ash disposal cost and for the recovery of those costs to be adjudicated in a future proceeding. Tr. Vol. 12, pp. 146-47.

D. The Positions of Intervenor Parties other than the Public Staff

AGO witness Wittliff maintained that the Dan River ash release was largely responsible for the development of CAMA in its present form, which he said accelerated remediation and closures and narrowed the field of removal and closure options. Tr. Vol. 11, pp. 239, 248-50, 272. He claimed that the plea agreements into which the Company has entered evidence harm to the environment caused by DEC's criminal negligence. Id. at 239-41, 265-67, 272-73. He also claimed that the Company's actions and inactions resulted in environmental harm and the incurrence of compliance costs that could have been significantly lower or possibly even avoided. Id. at 274-75. He asserted that, by not building new lined surface impoundments when it was "obvious" that additional impoundments were needed and would better protect the environment, the Company delayed and avoided potential exposure to requirements for more rigorous environmental controls on the new impoundments. Id. at 255. He questioned the Company's diligence with respect to managing dam safety, contended that the Company did not comply with the requirements of its ash basin permits at Dan River and Riverbend, and asserted issues of vegetation control and stability of impoundments at other facilities. Id. at 255-63, 273-74. He also claimed that the Company's 10-K filings with the Securities and Exchange Commission (SEC) show Duke Energy's awareness of trends in coal ash management and regulation towards lined impoundments. Id. at 236-38. Witness Wittliff further questioned Company witness Kerin's expertise with regard to coal ash issues and claimed that the Company's coal ash handling practices were not consistent with industry. Id. at 268-69.

At the hearing, in response to questions by counsel for the Company, witness Wittliff admitted that, while his testimony stated that he would support a Commission finding that the coal ash costs incurred by DEC were unreasonable and imprudent, his actual position is that the Company should be able to recover its costs to comply with the CCR Rule, but nothing more. Tr. Vol. 11, pp. 279-81. However, in its post hearing brief the AGO, on whose behalf witness Wittliff testified, maintained that all of DEC's 2015-2017 CCR remediation costs should be disallowed. Witness Wittliff stated that costs incurred by the Company to comply with the CCR Rule are reasonable and prudent. Id. at 282-83. He admitted that he did not identify any specific costs that could have been lower or should be disallowed. Id. at pp. 287-89. In response to questions regarding environmental compliance issues at electric power stations at which he had worked over the course of his career, witness Wittliff testified that he was not in a position at those times to say what those companies should or should not have done with respect to environmental compliance, but that he is in such a position now with respect to DEC, to say what should have happened with the Company's previous coal ash management. Tr. Vol. 11, p. 289 – Tr. Vol. 12, pp. 13-24.

CUCA witness O'Donnell opined that DEC should only recover costs to comply with the CCR Rule, not any costs under CAMA that exceed CCR Rule compliance costs, based on his contention that Duke Energy caused CAMA. Tr. Vol. 18, pp. 59-60. Witness O'Donnell purported to compare the DEC coal ash ARO to what he termed similar coal ash AROs of utilities across the United States. He concluded that the Company's ARO coal ash costs are among the highest in the nation, and contended that the only discernable difference between the Duke Utilities and the other utilities in his comparison was CAMA, which he asserted was prompted by the Dan River spill. He stated that DEC did not provide a similar financial analysis for this case. Id. at 56, 61-66. He asserted that there is no evidence to suggest that Duke's coal ash situation is significantly different from that of utilities across the country or from that of utilities in neighboring states. He claimed the Company failed to provide any evidence to counter his argument that its mismanagement led to excessive costs associated with its coal ash cleanup, and that because the Company chose not to dissect his analysis "bit by bit," that gives his evidence more credence. Id. at 66.

Sierra Club witness Quarles evaluated the methods DEC has proposed to close existing coal ash ponds at the Allen and Marshall plants and opined as to environmental conditions that may be associated with capping those ponds in place. He asserted that he evaluated site conditions at each location and the likelihood that DEC will be able to meet closure performance standards in the CCR Rule if it opts for cap-in-place closure. He also asserted that continued storage of coal ash at Allen and Marshall poses significant environmental risks. He stated that the coal-fired power plant industry recognized in at least the mid-1970s that disposal of CCRs into unlined disposal units and within close proximity to groundwater was risky, and that construction of unlined disposal units after that time was unreasonable. He claimed it would have been consistent with industry practice at the time for DEC to close and remediate leaking impoundments and construct new, lined dry landfills. He asserted that the Company built new unlined disposal areas at Allen and Marshall, and that lined landfills and surface impoundments were commonplace and more cost effective than building unlined surface impoundments since the mid-1970s. Tr. Vol. 6, pp. 19-118, 120-22.

Witness Quarles stated that the unlined basins at these plants were constructed over named and unnamed stream valleys, with wastes submerged in groundwater, and groundwater flows into those basins from topographically higher elevations and will come in contact with submerged coal ash. He also stated that there are documented impacts to groundwater at these basins and that a cap will not prevent lateral inflow of groundwater from adjacent areas. He concluded that closure in place at these basins would allow continued contamination of downgradient groundwater and violate the technical standards of the CCR Rule, and that removal of coal ash from the Company's ash basins would reduce the concentrations and extent of this contamination. Lastly, witness Quarles stated that DEC's plan for closure-in-place is well documented by the coal power trade industry association as an inappropriate groundwater corrective action where CCRs are submerged in groundwater like at Allen and Marshall. Tr. Vol. 6, pp. 19-118, 122-24.

At the hearing, Witness Quarles did not dispute on cross examination by Company counsel that the 1988 Report to Congress stated that only about 25% of all facilities had liners to reduce offsite mitigation of leachate, that only 40% of generating units built since 1975 had liners, that only 15% had leachate collection systems, only one-third had groundwater monitoring systems and that such systems were more common at newer facilities, that coal combustion waste streams generally do not exhibit hazardous characteristics, and that EPA's tentative conclusion was that current waste management practices appear to be adequate for protecting human health and the environment. Witness Quarles also confirmed that he did not conduct a site-by-site engineering analysis of the cost to the Company to close and remediate leaking impoundments and construct new, lined dry landfills. Tr. Vol. 6, pp. 143-45. In response to questions by the Commission he admitted that he has not raised the concerns he raised in this proceeding regarding cap-in-place at Allen and Marshall with DEQ. Tr. Vol. 6, pp. 149-50.

In its post-hearing Brief, the AGO contends that ratepayers should not be forced to cover costs caused by DEC's historic imprudence in managing its coal ash basins. The AGO argues that the Commission needs to consider several factors when determining whether the costs incurred are recoverable in rates. The AGO outlines them as follows: 1- The first is DEC's history of imprudence; 2- DEC's costs must be reviewed in detail to evaluate whether and to what extent they are for property that is "used and useful" and are recoverable in ratebase; 3- DEC has insurance to cover a large portion of the coal ash remediation costs it seeks from ratepayers, and these insurance proceeds should be taken into account; 4- DEC's request for cost recovery relies on a petition for an accounting order allowing deferral of the costs that is untimely, unreasonable, and unjustified as a basis for retroactive recovery of expenditures that DEC incurred in 2015 and 2016; and 5- DEC's claim that it is "entitled" to the recovery of coal ash costs from prior periods if it proves the costs are "known and measureable," "reasonable and prudent," and "used and useful" is not consistent with the statutory ratemaking regime, in which rates are established and become effective prospectively in order to allow—but not guarantee—the opportunity for cost recovery, and the rates are presumed to be just and reasonable until new rates are established by the Commission.

The AGO disagrees with this Commission using a 1988 DEP case in its recent decision in Docket No. E-2 Sub 1142, regarding Duke's burden of proof of prudent and reasonable costs. The AGO states that under the Commission's "prudence framework" in the DEP Order recently issued, a utility's costs are presumed to be reasonable and prudent unless challenged, and the challenges presented must show three things: "(1) they must identify specific and discrete instances of imprudence; (2) demonstrate the existence of prudent alternatives; and (3) quantify the effects by calculating imprudently incurred costs." In re Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service In North Carolina, Docket No. E-2, Sub 1142, Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, at 196 (Feb. 23, 2018)("2018 DEP Order")(citing the 1988 DEP Rate Order at 15) The AGO contends that this framework essentially puts the burden of proof on Intervenors. The AGO argues that it should be up to DEC to prove that some or all of the detailed costs are not attributable to its poor history of operations.

The AGO argues that evidence that the Company was noncompliant with regulatory requirements shows its imprudence, and cites Commissioner Brown-Bland's dissent to the 2018 DEP Order, indicating that violations of statutes that have the purpose of protecting the public from harm to life or safety constitute negligence per se. <u>See</u> <u>Bell v. Page</u>, 271 N.C. 396, 156 S.E.2d 711 (1967); <u>Hampton v. Spindale</u>, 210 N.C. 546, 187 S.E. 775 (1936). The AGO contends that DEC's five criminal convictions should be conclusive evidence of imprudence.

The AGO states that the Commission may consider an agency's standards or determinations when making its own determination about the prudence and reasonableness of coal ash activities, but cannot simply substitute another agency's determination or standards for its own. <u>See</u> <u>State ex rel. Utils. Comm'n v. Carolina Water Service of North Carolina v. Public Staff</u>, 335 N.C. 493, 503, 439 S.E.2d 127, 132 (1994).

The AGO states that coal has been utilized for many decades and beginning in approximately 1950, DEC, like many utilities, used unlined earthen impoundments to deposit its CCRs. The AGO states that in the 1970s, the United States Department of Energy directed that research be done on coal ash residuals and that the research revealed that there was a "growing awareness that the discarded wastes from coal combustion are a serious potential source of surface and ground water contamination" and that the wastes "have the potential for causing great environmental damage if not properly handled." 1979 Los Alamos Report, Tr. Ex. Vol. 12, pp. 189-204. In 1988, the

EPA, in its Report to Congress on the topic of "Wastes from the Combustion of Coal by Electric Utility Power Plants," voiced concerns over the "substantial quantities of wastes" produced by electric utility power plants and concurred with the Los Alamos Report that "[t]he primary concern regarding the disposal of wastes from coal-fired power plants is the potential for waste leachate to cause ground-water contamination" from the potentially toxic metals in the ash due to the fact that "[m]ost utility waste management facilities were not designed to provide a high level of protection against leaching." 1988 EPA Report to Congress, Tr. Ex. Vol. 12, p. 228.

The AGO contends that before the North Carolina General Assembly passed CAMA, DEC's coal ash activities were governed by three important laws: North Carolina's Dam Safety Act, the federal Clean Water Act, and North Carolina's 2L Groundwater rules and that DEC violated all of these laws and standards.

First, the AGO alleges that DEC violated dam safety standards. The AGO states that during the five-year dam safety inspections between 1996 and 2009, all seven of the facilities were cited for issues regarding seeps. Tr. Vol. 11, p. 259. Between 1996 and 2009, the five-year dam safety inspectors also expressed concerns regarding stability issues at the Allen, Dan River, Marshall, Cliffside, and Riverbend Steam Stations. Tr. Vol. 11, pp. 261-262. After the TVA incident, the dams at these facilities were all rated by the EPA in 2009 as having either high hazard potential or significant hazard potential.

Second, the AGO alleges that DEC violated the Clean Water Act citing, among others, that in 2015, Duke pled guilty to five counts of criminally negligent violations of the Clean Water Act. In addition to the four charges involving Dan River, one charge stemmed from the unauthorized discharge of pollutants from an unpermitted channel that allowed contaminated water from its coal ash basin at its Riverbend Steam Station to be discharged into the Catawba River from at least November 8, 2012 through December 30, 2014. Ex. Vol. 12 pp. 355-356, 400-01; Ex. Vol. 12, pp. 302, 346-347. The AGO also cites that after the Southern Environmental Law Center threatened to filed civil lawsuits, DEQ initiated lawsuits against all of the Company's facilities which was resolved by the parties. The AGO also cites that on March 4, 2016, the DEQ issued Notices of Violation to Duke Energy Carolinas related to seeps. Tr. Vol. 11, p. 267. On January 8, 2018, the Company announced its entry into a proposed Special Order by Consent with DEQ to settle alleged water quality violations at the Allen, Marshall, and Cliffside Steam Stations. Id. Each of the seeps identified and addressed in the Special Order exhibited some indication of the presence of coal ash wastewater. Id. The Company paid $84,000 ($4,000 each for 21 seeps identified at these facilities prior to January 1, 2015) and committed to dewatering six coal ash ponds at these three facilities. Id. The resolution of these seeps is independent of the requirements of the CCR Rule and CAMA, and therefore any activities employed to resolve these seeps should be disallowed. Id.

Third, the AGO claims that DEC violated the 2L groundwater standards citing that in 2012 and 2013, when all of Duke's sites were monitored and the groundwater data gathered, the Company found and the EPA noted that there were exceedances of the groundwater 2L standards at all eight sites. 40 CFR Parts 257 and 261, 80 Fed. Reg. 74

(Apr. 17, 2015), p. 21455; AGO Late-Filed Exhibit 1-K-Nov. 4, 2013 Ash Basin Groundwater Summaries. The AGO provides that the Company gave notice of potential legal claims arising from groundwater contamination to its insurers in 1996 and 1997. In that correspondence, Duke advised its insurance carriers, AEGIS and Lloyd's of London, that it may have legal exposure for pollutant discharges from coal combustion residuals ponds at its coal-fired power stations. Ex. Vol. 10, p. 528; Ex. Vol. 10, p. 538. The AGO further states that on November 3, 2013, Duke Energy Corporation prepared a breakdown of data regarding exceedances of the 2L water quality standards for all of its facilities and found exceedances at all eight of the Company's plants. AGO Late-Filed Exhibit 1-K-"Nov. 4, 2013 Ash Basin Groundwater Summaries" Duke_USAO_01448182. Significantly, Allen Steam Station, Buck Steam Station, Dan River Steam Station, and W.S. Lee Steam Station had exceedances of both the primary and the secondary standards. Lastly, in its settlement of the 2013 court case, DEC agreed to perform groundwater remediation per CAMA and 2L. The AGO argues that CAMA only applies to surface impoundments, not inactive ash areas, N.C.G.S. 130A-309-200 <u>et</u> <u>seq.</u> (2017); therefore, any costs associated with the excavation and removal of inactive ash areas are patently related only to the Company's violation of groundwater regulations and should be disallowed.

The AGO further argues that DEC disregarded the law citing that Mr. Wells testified that "there was no obligation in the 2L rules to monitor groundwater quality" after the corrective action requirements were added, and in fact, the Company considered itself "under no universal obligation to monitor for groundwater impacts" until required to do so via a NPDES permit or other regulatory requirement mandated by the regulatory agency. Tr. Vol. 24, pp. 229-230. The AGO argues that the 2L Rules, since their promulgation in 1979, are and have always been founded on strict liability and self-enforcement principles. 15A N.C.A.C. 02L .0101 <u>et</u> <u>seq.</u> As stated in its Policy provisions, "[n]o person shall conduct or cause to be conducted, any activity which causes the concentration of any substance to exceed" the water quality standards specified in these Rules. 15A N.C.A.C. 02L .0103(d) (2017). As these Rules "are applicable to all activities or actions, intentional or accidental, which contribute to the degradation of groundwater quality," DEC had a duty to comply with these Rules. <u>Id.</u>

Next, the AGO argues that DEC understood the changing regulatory landscape for years and did not change its practices. The AGO cites many documents that prove this point. The AGO contends that as early as 2003, more than ten years prior to the enactment of CAMA and the Federal CCR Rule, DEC knew that at some point in the future, it would no longer be able to store wet ash in unlined surface impoundments but did nothing about it. Ex. Vol. 16, Pt. 2, p. 123. In January 2007, DEC noted that it would "be required to construct landfills for disposal of its non-saleable CCP . . . in the years to come …" Ex. Vol. 16, Pt. 3, p. 50. In a document called "Duke Energy Environmental Management Program for Coal Combustion Products" dated May 29, 2007, Duke called "disposal in surface impoundments" the highest risk method of disposition of coal ash, and stated that this risk assessment should be used to support planning and management decisions. Ex. Vol. 16, Pt. 3, p. 60. In its 2010 Securities and Exchange 10-K filing, Duke Energy Corporation advised that it currently estimated that it would spend $131 million "over the period 2011-2015 to install synthetic caps and liners at existing and new CCP landfills and to convert some of its CCP handling systems from wet to dry systems to comply with current regulations." Ex. Vol. 16, Pt. 3, p. 238. Other documents include a 2013 Ash Basin Closure Strategy (AGO Late-Filed Exhibit 1-E-"Ash Basin Closure Strategy" p. Duke_USAO_01448357), review notes of an Environmental Review given to the Board of Directors of Duke Energy Corporation on August 27, 2013, (AGO Late-filed Exhibit 1-I.), and a presentation made to the Senior Management Committee on the "Ash Basin Closure Strategy on November 25, 2013. AGO Late-Filed Ex. 1-L p. Duke_USAO_1329810. The AGO states that in January 2014, less than a month before the Dan River spill, Duke Energy Corporation's Senior Vice President of Environmental Health and Safety acknowledged in a presentation to the Senior Management Committee that the Company's "coal ash is impacting the groundwater at all locations [and that] [t]his is not an overnight event, ash has been managed in this fashion for decades and it will take decades to close the ponds." Ex. Vol. 10, p. 611. Two of the recommendations given to the Senior Management Committee were to 1) "aggressively pursue closure of ash ponds at all decommissioned sites" and 2) "close all active ash ponds." Id. at 659. The AGO argues that despite the need to pursue the closure of its ash ponds and to convert to dry ash handling, DEC never implemented its own internal recommendations prior to the Dan River spill and the enactment of CAMA and the Final CCR Rule.

Next, the AGO argues that DEC failed to meet industry standards as it failed its duty to be a reasonable and prudent operator. The AGO further argues that under any standard, the Intervenors have shown the costs are not reasonable for cost recovery. The AGO states that it has shown discrete instances of imprudence, that prudent alternatives existed, and that imprudently incurred costs are enormous and certain disallowances should be made by the Commission. The AGO further argues that the Commission may "not allow an electric public utility to recover from the retail electric customers of the State costs resulting from an unlawful discharge to the surface waters of the State from a coal combustion residuals surface impoundment." N.C. Gen. Stat. § 62-133.13 (2014). This section of CAMA applies to discharges occurring on or after January 1, 2014. N.C.G.S. Session Law 2014-122, Sen. Bill 729, Part I, § (1)(b). The AGO states that it is not possible to determine exact disallowances, but the AGO contends that there are costs that would have resulted from the unlawful discharges to the surface waters of the State from at least the Riverbend plant cited in the Federal criminal case from January 1, 2014 to December 30, 2014. Ex. Vol. 12, pp. 400-401.

Next, the AGO submits that DEC should not receive "carrying costs" during amortization of the deferred CCR costs by placing the unamortized balance in rate base because the deferred CCR costs are not used and useful but rather are special operating expenses. According to the AGO, operating expenses are recoverable without return pursuant to N.C. Gen. Stat. § 62-133(b)(3) and State ex rel. Utils. Comm'n v. Thornburg (Thornburg I), 325 N.C. 463, 475, 385 S.E.2d 451, 458 (1989). Further, the AGO submits that the unamortized balance of the CCR deferred costs are similar to those considered in State ex rel. Utils. Comm'n. v. Carolina Water, 335 N.C. 493, 507, 439 S.E.2d 127, 135 (1994) (Carolina Water), where the Supreme Court considered whether the Commission erred when it treated utility plant that was not in service at the end of the test year – and would not be returned to service – as "an extraordinary property retirement," allowed amortization of the unrecoverable costs over ten years, and included the unamortized portion in rate base. The Court concluded that the costs were for plant that was not used or useful and, thus, the unamortized costs should not have been included in rate base. As the Supreme Court explained: "Including [these] costs in rate base allows the company to earn a return on its investment at the expense of the ratepayers." Id. at 508, 439 S.E.2d at 135.

Further, the AGO contends that the coal ash activities and expenditures are no longer related to ongoing or active property used or useful for providing utility service. The AGO states as support for this position that the costs in the asset retirement obligation are for the closure of basins and disposal of coal ash that Duke has identified with retired coal-fired steam stations (Ex. Vol. 16, Pt. 1, p. 24); the AGO argues that these coal ash closure and disposal costs are typically recovered in depreciation expense for long-term assets, as is recognized in the Commission's 2003 Order on Asset Retirement Obligations, DEC's internal evaluation of coal ash in 2014 contemplated the use of depreciation reserve funds, and Duke response to questions about whether such costs are included in depreciation expense in which DEC stated that the costs were not thought to result in a net negative salvage value, not that depreciation is inapplicable to such costs (Ex. Vol. 10, p. 691); depreciation costs are recovered over the 'useful life' of the asset. The AGO argues that no attempt has been made to define a useful life for the "property" that has generated coal ash expenditures and the retired plants where most of the costs were incurred do not have a remaining 'useful life' and no attempt has been made to identify the cost components, or consider the distinction between expenditures at operating versus retired plants or between expenditures such as those for construction of a landfill versus transportation costs.

The AGO posits that the fact that Duke has created an Asset Retirement Obligation for the coal ash expenditures does not dictate how the Commission must treat the costs for regulatory purposes. Deferral accounting is used to keep the regulatory accounting the same until a change in regulatory accounting is authorized. The AGO argues that imposing these coal ash costs on current ratepayers raises intergenerational fairness given DEC's failure to take action earlier. The AGO highlights that the Commission has previously dealt with the intergenerational issue when it considered whether to allow the recovery of manufactured gas plant clean-up costs based upon new environmental requirements. The AGO states that the Commission allowed recovery of the clean-up costs, however the amount was amortized over a period of years and no carrying costs were allowed on the unamortized balance.

The AGO contends that DEC's request to recover the deferred costs involves single-issue ratemaking, i.e., Duke seeks to recover coal ash costs going back to the beginning of 2015 – plus carrying costs – without review of the other rate elements that were in effect in 2015 that might offset the need for the cost recovery. With respect to the ARO, the AGO contends that DEC failed to request authorization to defer the coal ash costs before they were incurred and that the deferral in this case relates to Duke's establishment of an Asset Retirement Obligation for costs that are already accounted for in rates through amortization and depreciation. Lastly, the AGO argues that Duke's proposal to recover $201 million per year for ongoing coal ash costs as regular operating expenses is unreasonable and should be denied. Instead, Duke should be authorized to defer future costs for recovery in a future general rate case.

In its post-hearing Brief, CUCA contends that DEC's request for 100% CAMA compliance cost recovery is not appropriate. CUCA submits that DEC's costs are overstated and that many are the result of DEC's negligence, which is most clearly highlighted in DEC's guilty plea in the federal criminal environmental proceeding. CUCA supports an equitable sharing of the CCR cleanup costs due to the fact that CAMA costs are much higher than the CCR Rule compliance costs and that DEC's mismanagement directly led to the passage of CAMA. CUCA states that a 25% recovery is equitable. Further, CUCA contends that the CCR Rule is a self-implementing rule which has not been triggered by any citizen suits, and that in the absence of a regulatory directive to do so, DEC should not have pursued regulatory closure of operating sites. CUCA asks the Commission to revisit its analysis of management penalty in the DEP rate case order stating that the $30 million penalty amounts to a 1%[55] penalty which is too low based upon the evidence of DEC's negligence and criminal acts to come to a more fair result in this case. CUCA contends this division of costs sends the message that DEC is not being held responsible for its actions. Lastly, if the Commission does allow a similar 1% penalty in this case, it should also decrease the return on equity as DEC becomes a less risky company.

In its post-hearing Brief, CIGFUR III argues that DEC should not be allowed an equity component in the calculation of its deferred coal ash remediation carrying costs and that the appropriate amortization period is ten to fifteen years as opposed to five. CIGFUR III states that the total cost to defer is $497 million and that the carrying charges associated with the incurred coal ash costs since 2015 are $27 million, $6 million is associated with the cost of debt and $21 million is associated with the cost of equity. CIGFUR III further states that amortizing over 5 years results in annual amortization expense of $104.8 million, plus a $29.9 million net tax return, for a total requested revenue requirement of $135 million for deferred coal ash pond closure costs. CIGFUR III argues that the carrying costs should not include the equity component and that the deferral should be financed at the lowest option, which is the cost of debt. Allowing the equity component increases the amount charged to DEC's ratepayers and is inappropriate for such a significant expense that fails to enhance reliable service. CIGFUR III submits that the CCR costs were incurred over many decades and the stored coal ash is no longer used and useful in the provision of electric service. With respect to the run rate, CIGFUR III argues that DEC should not recover the run rate of $201 million and that DEC should defer ongoing costs for future recovery in its next rate case.

Sierra Club, in its post-hearing Brief, first discusses the legal standard for setting just and reasonable rates. Sierra Club argues that the closure of DEC's CCR basins is

[55] One percent relates to the penalty amount in relation to the Company's total CCR expenditures to comply with CAMA and the CCR rule, including future expenditures. Further, in relation to the DEP case, the 1% does not include the approximately $10 million discrete disallowance for transportation costs.

not in direct response to the CCR Rule or CAMA, but was made necessary because of DEC's unlawful discharges of CCR constituents to surface waters, and, therefore, DEC's closure costs are not recoverable under N.C. Gen. Stat. § 62-133.13. Further, Sierra Club contends that all of DEC's CCR basins are unlawfully discharging pollutants into surface waters and/or groundwaters, and that the only way to stop these unlawful discharges is to close the ponds and eliminate the source, the coal ash. Therefore, Sierra Club concludes that the cost of pond closures results from the unlawful discharges and are not recoverable.

Sierra Club submits that DEC failed to meet its burden to prove that storage of CCRs in unlined, leaking basins for decades was a reasonable and prudent way for DEC to manage its CCRs. According to Sierra Club, the DEC evidence provided by witnesses Kerin, Wells and Wright about the historical handling of CCRs being reasonable, prudent and consistent with industry standards over time is not credible. Rather, Sierra Club contends that: (1) DEC's groundwater monitoring did not comply with the EPRI standards set forth in EPRI's CCR manuals; (2) that DEC's continued use of unlined basins was contrary to the national trend toward lined basins or dry fly ash handling systems; and (3) that DEC's response to the surface water and groundwater pollution shown by its monitoring reports, once it finally began monitoring, was not reasonable or adequate. Sierra Club states that DEC's first facility to be converted to dry fly ash handling was the Belews Creek plant in 1983, after DEC became aware that selenium from sluiced coal ash was killing the fish in Belews Lake. The result, according to Sierra Club, was a 75% decrease in selenium concentrations.[56] Yet DEC did not use this information and experience to perform investigations at other plants, or to convert to dry fly ash handling at other plants.

Sierra Club also cites DEC's criminal pleas as evidence that DEC allowed unauthorized discharges of pollutants into surface waters. Sierra Club states that the environmental audits conducted as a part of DEC's plea arrangement identified unauthorized seeps containing pollutants above background levels at all DEC plants. Sierra Club contends that the evidence these unauthorized discharges of pollutants have been occurring for an undisclosed amount of time, and, pursuant to N.C. Gen. Stat. § 62-133.13, provide the basis for the Commission to deny all costs of dewatering the CCR basins, at a minimum.

With regard to groundwater pollution, Sierra Club states that DEC failed to follow the industry standard for monitoring compliance with the 2L requirements and, instead, conducted initial sampling at the Allen plant, then extrapolated that data to conclude that there was no violation of the 2L standards at DEC's other seven plants. Sierra Club contends that DEC did not conduct consistent groundwater monitoring at all of its plants until the 2000s, and that similar to the surface water audits the court ordered ground water audits found that CCR constituents are in the groundwater beneath all of DEC's CCR basins. In addition, Sierra Club points to DEC's 1996 insurance letter as proof that DEC

[56] The selenium levels of concern at this site were from water discharges allowed from the NPDES permit rather than from groundwater leachate.

knew about contamination above the 2L standards at Allen, Belews Creek, Dan River, Marshall and W.S. Lee as early as 1996.

Sierra Club submits that the manner in which DEC failed to inspect and maintain the Dan River basin is indicative of its history of mismanagement and inaction with respect to CCR, and that this is conclusive evidence of imprudence, along with the following decisions made by DEC during the last 30 years:

(1) Failing to follow industry standards to stop using unlined basins.
(2) Waiting 20 years after the fish kill at Belews Creek to convert other plants to dry fly ash handling.
(3) Not conducting preliminary site investigations at all plants after the fish kill at Belews Creek.
(4) Waiting 30 years to regularly monitor ground water, contrary to the industry standard as of 1981.
(5) Not taking any action in response to the 1981 or 1982 EPRI manuals or the 1988 EPA Report, such as switching to lined basins, monitoring groundwater and dewatering basins.
(6) Spending millions of dollars on a leachate collection system at Allen and Marshall, then dumping the leachate into unlined basins at Allen and Marshall.

Moreover, Sierra Club argues that DEP's closure plans for its Allen and Marshall CCR basins do not comply with the CCR Rule or protect against continued discharges, and, therefore, DEC's proposed run rate should be rejected. Sierra Club contends that capping in place the Allen and Marshall CCR basins will not protect against continued contamination of ground water due to leaching of coal ash constituents into groundwater or into surface waters through migration.

NC WARN contends that DEC should not be allowed to recover any costs for the mitigation and cleanup of its CCR basins based on its extensive managerial mistakes and failures to take prompt action to correct known liabilities, and that no CCR costs should be borne by ratepayers. According to NC WARN, DEC has not met its burden of showing which of its CCR costs are capital expenses and which are operating expenses, N.C. Gen. Stat. § 62-133(b)(1) limits rate base recovery in rates to "property used and useful," and the statute does not include operating costs. As such, DEC's costs of compliance with federal and state directives stemming from CCR violations, and court orders mandating cleanup cannot be placed in rate base or otherwise recovered.

NC WARN also states that a review of the NC Clean Smokestacks Act is helpful because it provides guidance on what costs should not be allowed, such as costs incurred by the utility for failure to comply with any federal or state law, rule, or regulation for the protection of the environment or public health, and criminal or civil fines and penalties. N.C. Gen. Stat. § 62-133.6(a)(2). NC WARN asserts that the evidence shows that all of the costs incurred by DEC relating to CCR came from court orders and criminal plea agreements, and that DEC took no actions voluntarily, even actions that could have minimized subsequent costs and mitigated environmental damage. Further, NC WARN states that the evidence shows that DEC "knew or should have known" about the significant problem of leaking CCR basins in the early to mid-1980s, if not before, and that the industry standard increasingly became lining CCR basins to prevent water contamination. NC WARN points to DEC's insurance letters in 1996, 2011, and 2016 regarding potential damages and future compensation for mitigation and cleanup costs as significant evidence of what DEC knew or should have known, and contends that the refusal by the insurance companies to cover these multi-million dollar claims demonstrates DEC's culpability for at least the last 20 years. In conclusion, NC WARN submits that DEC mishandled its coal ash for decades, taking the least expensive options, and disregarding the substantial negative impacts of coal ash on families, property, and water supplies adjacent to the coal ash basins, and that the evidence demonstrates criminal negligence, millions in fines and penalties, and a number of judicial decisions and regulatory actions requiring DEC to do what it should have done all along.

E. The Position of Public Staff Witnesses Garrett and Moore

Public Staff witnesses Garrett and Moore testified that they investigated the prudence and reasonableness of costs incurred by DEC with respect to its coal ash management. In addition, they reviewed the approach taken by DEC to determine the least cost method of achieving compliance with the laws and regulations governing coal ash management. Witnesses Garrett and Moore testified that in some circumstances, DEC incurred costs associated with management of coal ash from CCR units that were not required under State or federal law. In those circumstances, witnesses Garrett and Moore evaluated the specific facts and details surrounding those CCR units to determine whether they agreed that DEC's management of those CCR units was reasonable and prudent. To the extent they believed that DEC's actions and costs incurred were not reasonable nor prudent, they recommended that the Commission disallow these costs. In conducting their investigation, witnesses Garrett and Moore reviewed the closure plans and coal ash-related costs incurred for all of DEC's coal-fired facilities, conducted extensive discovery, participated in numerous meetings, and visited several of the DEC facilities in question. Tr. Vol. 21, pp. 19-20.

Witnesses Garrett and Moore did not take exception with DEC witness Kerin's general characterization of the applicable federal and State regulations addressing the management and closure of coal ash basins in North Carolina and South Carolina. They did, however, identify several decisions made by DEC they maintained that were not required by law or where lower-cost compliance options were available, which they described in further detail in their testimony. Tr. Vol. 21, pp. 20; 50.

With regard to DEC's Allen, Belews Creek, Buck, Cliffside, and Marshall plants, witness Moore noted that DEQ issued final classifications for these facilities as "Low to Intermediate Risk" in May 2016, and that DEP is in the process of establishing the permanent replacement water supplies required under N.C. Gen. Stat. § 130A-309.211(c)(1) and performing the applicable dam safety repair work at these sites. Tr. Vol. 21, p. 54. Upon completion of these tasks within the timeframe provided, the impoundments at these facilities will be reclassified as low-risk pursuant to N.C. Gen. Stat. § 130A-309.213(d)(1). He explained that CAMA requires, at a minimum, that the impoundment be dewatered and closed either by excavation or by placement of a cap system that is designed to minimize infiltration and erosion. Witness Moore noted that this approach is generally the most cost-effective means for closure of a CCR unit. He also testified that CAMA (S.L. 2016-95) does not require the submission of proposed closure plans for low- and intermediate risk impoundments until December 31, 2019, so DEC has not submitted a Site Analysis and Removal Plan (SARP) to DEQ for any of the Low to Intermediate risk facilities at this time. He maintained, therefore, that a prudence review of the closure plans would be premature, so witness Moore took no exception in the present case to DEC's current proposed closure method for the coal ash basins located at Allen, Belews Creek, Buck, Cliffside, and Marshall. Tr. Vol. 21, pp. 55-57.

Public Staff witness Moore took exception to DEC's closure method for the CCR units located at Buck Steam Station. Duke selected Buck, along with DEP's Cape Fear and H. F. Lee Stations, as the three beneficiation sites pursuant to N.C. Gen. Stat. § 130A-309.216, which required Duke to identify three sites located within the state with ash stored in the impoundments suitable for processing for cementitious purposes. 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 processed ash to be removed from the impoundments located at the sites. Tr. Vol. 21, pp. 58-61. Witness Moore also noted that the timeframe proposed by DEC for beneficiation of the Intermediate Risk sites extends beyond the closure timeframe called for in Section 3.(a) of S.L. 2016-95 for sites deemed Intermediate Risk, and that N.C. Gen. Stat. § 130A-309.215 provides a variance option for closure deadlines that are found to be in the public interest. Id.

Public Staff witness Moore testified that instead of selecting Buck, Duke should have selected the CCR units located at Weatherspoon as one of the three beneficiation sites as required by N.C. Gen. Stat. § 130A-309.216, where Duke has selected the excavation of CCR and beneficial use option, with contracts in place for the delivery of the coal ash material to facilities in South Carolina for use in the concrete industry. This would have allowed the Buck Station to instead utilize significantly lower cost closure options instead of cementitious beneficiation. CCR units at Buck could have been classified as low risk upon completion of the establishment of permanence replacement water supplies and completion of applicable dam safety repair work, and instead may have been eligible for closure under the "cap-in-place" closure method under CAMA, which would have significantly lowered closure costs for Buck. Tr. Vol. 21, pp. 59-61. Witness Moore therefore recommended that the Commission disallow the $10 million already incurred by DEC for the cementitious beneficiation project at Buck. Tr. Vol. 24, p. 108.

With regard to DEC's selected closure actions at the Dan River Plant, witness Moore took exception with DEC's decision to excavate and transport coal ash from Ash Stack 1 at Dan River off-site to the Maplewood Landfill in Amelia, Virginia. He contended that had DEC conducted an adequate assessment of on-site greenfield landfill options at the time it began evaluating off-site disposal options, it would have identified viable on-site disposal options that would have allowed DEC to dispose of all of the ash on-site without having incurred the added expenses associated with the off-site transfer and disposal. Tr. Vol. 21, pp. 62-70.

Witness Moore disputed DEC's position that the moratorium on CCR landfills, which was enacted on September 20, 2014, in Section 5.(a) of S.L. 2014-122, and expired on August 1, 2015, had any impact on DEC's ability to construct an on-site greenfield landfill at Dan River in a timely fashion. He also noted that there were no regulatory obligations related to coal ash management that required removal of CCR materials from Ash Stack 1 as stated by DEC, particularly under the aggressive timeframes required for high-priority sites under CAMA. He evaluated DEC's investigation of on-site landfill options, particularly along the western boundary of the property, and found that DEC had no records documenting any evaluation of the area. With regard to the reasons provided by DEC as to why it did not utilize the area between the combined cycle plant and the western property boundary, Public Staff witness Moore found no valid technical reasons why an adequately sized on-site landfill could not have been located along the western boundary to have handled all of the ash on-site without having to incur the significant costs associated with off-site transportation costs and construction of rail handling equipment. Tr. Vol. 21, pp. 64-66.

As a result of DEC's unnecessary actions to transport ash off-site from the Dan River facility, witness Moore recommended a total disallowance at the Dan River facility of $59.3 million from DEC's coal ash expenditures during this recovery period. Public Staff Moore Exhibit 4.

Witness Moore summarized the coal ash closure approach taken by DEC at its Riverbend facility. Witness Moore testified that CAMA required the excavation of CCR materials from the Primary Ash Basin and the Secondary Ash Basin, but there were no regulatory obligations that required removal of CCR materials from the Ash Stack Area or the Cinder Pit. Witness Moore did not take exception with DEC's plan to remove this additional material, but he did take exception with DEC's decision to utilize the Brickhaven structural fill facility for off-site disposal. Tr. Vol. 21, p. 70, 72. Witness Moore testified that the Brickhaven facility did not present any scheduling advantages or reduce costs, and instead resulted in increased delays and litigation resulting from community opposition to the proposed project. Witness Moore testified that the DEC-owned on-site landfill at the Marshall Facility should have been utilized for the disposal of all ash from Riverbend. Tr. Vol. 21, p. 86.

Witness Moore did, however, take exception to DEC's decision to haul approximately 17,000 tons of CCR material from the Ash Stack Area by truck to the R&B Landfill in Homer, Georgia. Instead, Witness Moore stated that DEC could have utilized the landfill at the Marshall Facility for the CCR material, resulting in shorter hauling distances and lower disposal costs. Witness Moore recommended that the Commission disallow the $489,600 premium paid to transport and dispose of the 17,000 tons of CCR material to the R&B Landfill, as opposed to the Marshall Station. Tr. Vol. 21, pp. 72-74.

Public Staff witness Garrett focused his testimony on the activities undertaken by DEC at its W.S. Lee site in South Carolina. Witness Garrett agreed with DEC's decision to utilize an on-site landfill to dispose of the ash material in the Primary Ash Basin and Secondary Ash Basin at W.S. Lee, noting that this approach was consistent with Duke Energy's stated guiding principles and provided a lower cost closure solution compared to an off-site landfill. Tr. Vol. 21, pp. 39-40. Witness Garrett also concurred with DEC's decision to take some actions at the Inactive Ash Basin (IAB) and the Old Ash Fill to mitigate risk associated with long-term environmental issues at the site, but he did not agree with DEC's decision to immediately begin excavation and transportation of ash to the R&B landfill in Homer, Georgia. Witness Garrett instead testified that DEC should have followed the recommendations of its consulting engineers, which recommended repair and maintenance on the IAB berm in 2014, rather than immediate excavation. Witness Garrett further stated that DEC failed to provide a regulatory or technical reason to substantiate immediate removal of the ash from the IAB. Witness Garrett therefore recommended that the Commission disallow approximately $27 million from DEC's request, which is the premium associated with the costs incurred by DEC to transport ash to Homer, Georgia, as opposed to excavating and landfilling on-site. Tr. Vol. 21, pp. 40-41.

Witness Garrett also took exception with DEC's plan to excavate and dispose of the coal ash material contained in the Structural Fill area at W.S. Lee, because the area was developed in accordance with all applicable environmental regulations, is not in close proximity to the Saluda River, has been effectively capped in place, and does not pose any environmental concerns in its present state. Id.

F. Public Staff Witness Junis' Equitable Sharing And Coal Ash Adjustment Testimony

Public Staff witness Junis listed three conceptual options for regulatory treatment of coal ash costs. The first option is to allow full recovery of coal-ash related costs on the grounds that the costs have been reasonably incurred to comply with CAMA and the CCR Rule. Tr. Vol. 26, p. 721. This is essentially the approach recommended by DEC, minus fines, penalties, and other specific costs listed in their federal criminal plea agreement as non-recoverable in rate proceedings. Id. The second option is to disallow recovery of costs to comply with CAMA on the grounds that CAMA is the direct consequence of imprudent DEC environmental violations. Tr. Vol. 26, pp. 721-22. The third option is to disallow the costs incurred to defend and remedy environmental violations, except to the extent that CAMA requirements increased the cost of remediation. Tr. Vol. 26, p. 722. Under this approach, which the Public Staff advocates in theory, disallowances would be based on the costs to remediate environmental violations rather than the costs flowing from CAMA compliance. Id.

While the Public Staff supports the third option in theory, witness Junis encountered “complicating factors” that led him to modify this preferred regulatory treatment for practical reasons. Id. He observed that, while some environmental violations are clearly due to Company negligence, others fall into a gray zone where they are neither clearly imprudent nor clearly reasonable. Tr. Vol. 26, p. 723. For instance, decisions to place coal ash in unlined impoundments could have been reasonable based on what DEC knew or should have known at the time the basins were constructed some decades in the past. Tr. Vol. 26, pp. 723-24. At the same time, Public Staff witness Junis explained that it can be unreasonable to impose on ratepayers the costs incurred because those impoundments leaked coal ash constituents and contaminated groundwater outside the compliance boundaries, in violation of state environmental laws and regulations. Tr. Vol. 26, p. 724. Witness Junis also noted that calculating the costs of many environmental violations would be too speculative as such calculations would involve estimations based on scenarios that did not occur (e.g., preventing violations through basin construction or modification some decades earlier, or remedying violations if CAMA had not been enacted). Tr. Vol. 26, p. 725.

Due to the complicating factors, witness Junis offered a more practical approach that would exclude certain coal ash costs from recovery in rates as follows:

(1) DEC litigation costs incurred during the test year 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;
(3) fines, penalties, and other costs associated with the federal criminal plea agreement involving the Dan River and Riverbend plants, payments to DEQ to settle the assessment of penalties involving the Dan River plant, and the penalty for groundwater violations at DEC and DEP plants including Belews Creek and Sutton;
(4) the adjustments and disallowances recommended by Garrett and Moore to the extent there is no double disallowance for the same item; and
(5) an equitable sharing of the remaining allowed costs of coal ash management through the deferral and amortization approach recommended by Public Staff witness Maness.

Tr. Vol. 26, pp. 727-28.

Witness Junis noted that DEC has removed the costs listed in item (3) above from its rate request. Tr. Vol. 26, p. 728. Thus, the regulatory treatment of those costs is not in dispute. The disallowances recommended by witnesses Garrett and Moore are discussed elsewhere in this order. The remaining cost exclusions listed by witness Junis include litigation-related expenses in cases of environmental violations. In this category, he recommended exclusion of $2,109,406 (total system, not just NC retail, as shown in Boswell Exhibit 1, Schedule 3-1(n), line 1) of test year outside legal fees for litigation of the state enforcement actions filed by DEQ alleging violations at all of DEC’s North Carolina plants and, to any extent they have not already been excluded by DEC, for litigation of the penalties assessed by DEQ for violations at the Dan River plant. Tr. Vol.

26, pp. 730-31. Witness Junis asserted that there is compelling evidence of the environmental violations on which these legal actions were based. Tr. Vol. 26, p. 731. He referenced a number of the exhibits to his testimony detailing DEQ data in support of this assertion. Id.

For the category of costs to remedy environmental violations where the costs exceed what CAMA would have required in the absence of environmental violations, witness Junis identified, to date, $1,288,526 (total system) of expenditures incurred from January 1, 2016, through November 30, 2017, for extraction wells and treatment of groundwater at DEC's Belews Creek plant pursuant to the settlement agreement between DEQ and DEP in the Sutton penalty assessment case. Tr. Vol. 26, pp. 733-34. He took the position that these costs would not have been incurred but for unlawful contamination of groundwater by DEC's Belews Creek ash basins, and that these costs are over and above the lowest reasonable costs of CAMA compliance in the absence of violations. In addition to the costs associated with extraction wells and treatment of groundwater, witness Junis identified $857,350 of expenditures for selenium removal equipment at DEC's Riverbend plant on the grounds that this equipment had not been placed in operation at the time of his testimony. Tr. Vol. 26, p. 734. Witness Junis noted that there could be additional costs in this category in the future. Tr. Vol. 26, p. 732.

The final category for disallowance is based on an "equitable sharing" of all coal ash-related costs not otherwise disallowed. Tr. Vol. 26, p. 738. Witness Junis referred to witness Maness' testimony for description of how the equitable sharing should be implemented and the reasons for it. Id. Witness Junis further testified that "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." Tr. Vol. 26, p. 738. In support of his opinion, he noted the nature and extent of coal ash environmental problems addressed in the federal criminal plea agreement, unlawful discharges, dam safety deficiencies, and numerous groundwater violations. Tr. Vol. 26, p. 739. He added that the sheer number of legal actions against DEC for coal ash environmental violations, while not evidence of the Company's guilt, is suggestive of the extent of the problem. Tr. Vol. 26, pp. 739-40. Witness Junis asserted that the numerous lawsuits regarding DEC's non-compliance with N.C. Gen. Stat. § 143-215.1 and state groundwater rules would in all probability have led to environmental cleanup costs even if CAMA and the CCR Rule had not been adopted, and that the costs of impoundment closures under CAMA and the CCR Rule overlap what would otherwise have been coal ash cleanup costs under existing state and federal environmental laws and regulations. Tr. Vol. 26, p. 741. Based on DEC's culpability for environmental violations, witness Junis testified that an equitable sharing would be appropriate, whereas it would be unreasonable and unjust to burden ratepayers with all the coal ash-related costs when ratepayers were not culpable for the environmental violations. Tr. Vol. 26, pp. 741-42.

Witness Junis responded to DEC witness Kerin's assertion in his testimony that the EPA's 2015 Effluent Limitations Guidelines (ELG) Rule forced DEC to convert its coal-fired plants to dry ash handling. Tr. Vol. 26, p. 742. Witness Junis noted that conversion to dry ash handling or cessation of operations is a requirement of CAMA, which was enacted in 2014, and, thus, the ELG Rule, which was not promulgated until 2015, was not the driver of this outcome in North Carolina. Tr. Vol. 26, p. 743.

Witness Junis disagreed with Company witness Kerin's testimony that DEC had not done anything to cause it to incur any unjustified coal ash-related costs, and he disagreed with witness Wright's minimization in his testimony of the role of the Dan River spill on the enactment of CAMA. Tr. Vol. 26, pp. 743-44. He stated that Dan River spill "was a large contributing factor to the creation of CAMA, which forced the Company to take expensive corrective actions." Tr. Vol. 26, p. 744. He further noted that Senate President Pro Tem Phil Berger recommended that the spill be discussed in the General Assembly's next meeting in a press release issued four days after the spill, and that the first version of CAMA directly referenced the spill in its preamble. Tr. Vol. 26, p. 745.

Witness Junis also disagreed with Witness Wright's assertion that the Commission should treat DEC the same as it treated DNCP in its 2016 rate case, in which the Commission approved amortization with a return for DNCP's past deferred coal ash costs. Tr. Vol. 26, p. 747. Witness Junis stated that the volume of environmental regulatory action against Dominion was miniscule compared to that against DEC, and that this was borne out by the Company's own responses to Public Staff Data requests in which it failed to produce evidence of environmental violations by DNCP after 1993. Tr. Vol. 26, p. 748.

In supplemental testimony, witness Junis recommended disallowance of an additional $206,553 in expenditures for groundwater extraction and treatment at DEC's Belews Creek plant listed in DEC witness McManeus' second supplemental testimony, which updated coal ash costs through December 31, 2017. Tr. Vol. 26, pp. 752-53. This recommendation is based on the same grounds for the disallowance of groundwater extraction and treatment costs detailed in witness Junis' direct testimony.

In his initially filed and supplemental direct testimony, Public Staff witness Maness identified the following seven adjustments to the Company's proposed recovery of coal ash costs. Some of the adjustments incorporate recommendations from other Public Staff witnesses:

a. Witness Maness incorporated adjustments to reflect a prudent and reasonable level of coal ash expenditures as recommended by Public Staff witnesses Moore, Garrett, and Junis. Tr. Vol. 22, pp. 65-66, 147, 153-54.

b. Witness Maness recommended adjusting the N.C. retail jurisdictional allocation factors to (a) allocate the costs DEC has identified as "CAMA Only" costs by the comprehensive allocation factor, rather than a factor that does not allocate costs to South Carolina retail operations; and (b) allocate all coal ash expenditures by the energy allocation factor, rather than the demand-related production plant allocation factor.

c. Witness Maness recommended addition of a return on deferred coal ash expenditures from December 2017 through April 2018, to bring the total balance up to the expected effective date of the rates approved in this proceeding. Tr. Vol. 22, pp. 69-70. The Company accepted this approach in its Second Supplemental Filing, as noted above. However, the Company has calculated the 2018 net-of-tax debt carrying cost using a Federal income tax rate of 35%; witness Maness recommended using the updated 2018 rate of 21%. Tr. Vol. 22, pp. 149-50.

d. Witness Maness recommended calculation of the return on the deferred coal ash costs be made with a mid-month cash flow convention, rather than the beginning-of-month convention used by the Company. Tr. Vol. 22, p. 70. The Company accepted this approach in its Second Supplemental Filing, as noted above. However, the Company had continued to apply compounding at the end of January each year. Witness Maness continued to recommend compounding carrying costs at the beginning of January each year. Tr. Vol 22, p. 149.

e. In conjunction with the Public Staff's proposal for equitable sharing of coal ash costs between ratepayers and investors, witness Maness recommended amortization of the balance of deferred coal ash expenditures over a 25-year period, rather than the 5-year period proposed by the Company. Tr. Vol. 22, pp. 70-85, 153-54.

f. Also in conjunction with the Public Staff's proposal for equitable sharing of coal ash costs between ratepayers and investors, witness Maness recommended reversal of the Company's inclusion of the unamortized balance of coal ash expenditures in rate base; this reversal, in conjunction with the 25-year amortization period, would produce a 49% ratepayers / 51% investors sharing of the burden of deferred coal ash expenditures. Tr. Vol. 22, pp. 70-85, 153-54, 162.

g. Witness Maness recommended removal of the ongoing annual expense amount, or "run rate," proposed by DEC 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 DEC's next general rate case.

G. Company Witnesses – Rebuttal

Rebuttal testimony with respect to the reasonableness and prudence of the Company's coal ash basin closure costs was provided by Company witnesses Kerin, Wright, and Wells. Rebuttal testimony with respect to witness Maness' proposed adjustments was provided by witness McManeus. Rebuttal testimony with respect to the Company's entitlement to earn a return on the unamortized balance of coal ash costs, ARO accounting and the "used and useful" concept, was provided by witnesses Wright, McManeus, and Doss. Such testimony is summarized as follows.

1. Kerin

Company witness Kerin's rebuttal testimony responded to the direct testimony of Public Staff witnesses Garrett, Moore, and Junis, CUCA witness O'Donnell, AGO witness Wittliff, and Sierra Club witness Quarles. As in the DEP proceeding, witness Kerin testified that witnesses Garrett and Moore engaged in a robust analysis and investigation of the costs that DEC incurred to comply with the CCR Rule and CAMA, and he agreed with the majority of their conclusions. He also stated that based on a complete review of the applicable facts and real world conditions, he did not believe their suggested disallowances were warranted, and that they again missed or overlooked key facts in several of their recommendations. Tr. Vol. 24, pp. 90-92.

First, he disagreed with witness Moore's conclusion that it was imprudent and unreasonable for DEC to transport CCR material from Dan River to a landfill in Virginia until the on-site CCR landfill could be constructed, and with their recommended disallowance of $59,320,890, which represents the difference between the cost to transport the material off-site and the cost to dispose of it in what he classified as a hypothetical and impractical on-site landfill along the western property boundary. Witness Kerin stated that witness Moore conceded that the CAMA moratorium prohibited construction of new or expanded CCR landfills located wholly or partly on top of the Primary Ash Basin, Secondary Ash Basin, and the Ash Fill 1 and 2 areas. He also stated that, while witness Moore correctly asserted that the moratorium did not prohibit construction of landfills in other areas of the site, specifically near the western property boundary, based on the Company's exploration of off-site and on-site locations for a CCR landfill for the Dan River ash, locating the on-site landfill on the western property boundary was never a feasible option due to multiple factors that witness Moore did not consider. Tr. Vol. 24, pp. 92, 94-105, 131.

Witness Kerin explained that in June 2015, Duke Energy purchased two tracts of land near Dan River (the Hopkins Tracts), which together with the Dan River plant were subject to a City of Eden zoning ordinance that made landfill construction on those properties cost prohibitive. He explained further that, while DEC and the City of Eden entered into an agreement whereby the City amended its zoning ordinance to allow landfill construction on the Dan River property, several limitations were imposed on the location of an on-site landfill. The landfill could only be located on the Dan River Facility premises, not on the Hopkins Tracts. In addition, the on-site landfill needed to be located near the existing basins, and as remote from residential areas as feasible. Witness Kerin noted that the nearest location to the existing basins is within the footprint of the former ash stack, and that this is the location DEC chose for the landfill. This choice also minimized impacts to surrounding properties by ensuring that the landfill was located as far as feasibly possible from neighboring properties. He stated that, because witness Moore's proposed location, in contrast, was not closest to existing basins or as remote as feasible from residential areas, the City of Eden would not likely have approved the zoning required to construct the landfill in this location. Witness Kerin stated that, if witness Moore had considered the City of Eden agreement, he could not have concluded that his alternative landfill location was reasonable or prudent. Tr. Vol. 24, pp. 95-96.

Witness Kerin maintained further that construction of the landfill in witness Moore's proposed location would require complete excavation of a LCID Landfill on the site. He explained that DEQ had allowed Duke Energy to dispose of asbestos in the Dan River LCID Landfill, and stated his opinion that North Carolina regulators would not allow DEC to disturb a covered landfill containing asbestos. This is because, while asbestos that is covered and in a landfill poses little to no risk to environmental health or safety, when uncovered and disturbed through excavation, it becomes friable and will be released into the air, posing an unacceptable risk to workers and, potentially, neighbors. Witness Kerin also testified that, even if the Company were allowed to excavate the LCID Landfill, disposal of the fill material would have posed additional challenges. While witness Moore asserted that the Company could have disposed of the material at the Rockingham County Landfill, witness Kerin stated that it is not clear that that location would have accepted the volume of asbestos—at least 60,000 cubic yards—required to be excavated from the LCID Landfill. Even if Rockingham would accept the asbestos, because it imposes strict double-bagging requirements for asbestos waste, this requirement would prohibit pursuing this alternative from an operational and labor standpoint. Tr. Vol. 24, pp. 97-98.

Witness Kerin stated that DEC also located the on-site landfill so that it does not interfere with existing streams and wetlands on the Dan River Plant premises. He stated that witness Moore's alternative location would in contrast interfere with two streams and two wetlands and impact several others, which would have required the Company to apply for U.S. Army Corps of Engineers (USACE) and DEQ permits to address those impacts. He also stated that, in the Company's experience, it is not likely that USACE would have approved the requisite permits, or would not have done so in time for the Company to meet the closure deadline of August 2019, especially considering that another on-site location – the one chosen by DEC – would have no impacts to streams or wetlands. He contended that witness Moore's proposal neither avoids nor minimizes impacts to jurisdictional waters, and relies solely on cost as support for his location. He asserted that the location that DEC chose for the landfill allowed it to proceed without litigation or delay, and will allow it to meet its CAMA imposed excavation deadlines. Tr. Vol. 24, pp. 98-100.

Witness Kerin maintained in addition that witness Moore's alternative location did not consider elevation changes and other topographical features, such as the steep slopes on the alternative site that lead to and through streams and wetlands. He also asserted that the steep grading limits the airspace that can be realized for developing a lined landfill of the size needed, and the elevation of witness Moore's proposed location would result in the landfill being in neighbors' line of sight. Witness Kerin also asserted that the land along the western property boundary is not suitable for landfill construction, as the depth to bedrock is fairly shallow, leaving little room for excavation for fill volume, borrowing soil or buffering to groundwater. He asserted further that the slope to stream combination on the western and southern sides of witness Moore's proposed landfill location leaves no area for stormwater management on the low side of the landfill, and that significant borrow resources would be required to fill the toe of the slope to achieve enough buffer from the stream for landfill access and stormwater features, adding expense and time to the project. Further, he maintained that the Company would have needed to obtain a new construction permit and construct an industrial NPDES outfall through the service water pond in order to build witness Moore's proposed landfill, and that both the permit and the outfall would have required substantial time to obtain and construct and would have to be in place before construction on the landfill began. In addition, he maintained that the 100-year flood plain in this area intrudes into portions of witness Moore's proposed location, and would present additional permitting challenges and likely not leave sufficient space for required stormwater management features on the site. Tr. Vol. 24, pp. 100-02.

Finally, with regard to Dan River, witness Kerin maintained that, even if DEC could have overcome all of the obstacles to witness Moore's proposed site, the proposed disallowance was incorrectly calculated. He explained that witness Moore did not correctly calculate the Company's costs for excavating, transporting, and disposing of Ash Stack 1 off-site, and that his proposed $83,531,985 disallowed should be reduced by approximately $3.8 million that is actually attributable to excavation and transportation of ash from the Primary Ash Basin. Witness Kerin also asserted that witness Moore's cost estimates to construct his alternative landfill are too low. He explains that when the presence of asbestos and the need to relocate the warehouse building in the center of the alternative location are accounted for, the cost to build witness Moore's alternative location landfill jumps by $10,790,900 to $35,001,095, thereby reducing witness Moore's proposed disallowance further, to $44,742,265. Witness Kerin emphasized that, because witness Moore's proposed site was not a viable option and never considered by the Company for the myriad reasons he discussed, this recalculation is hypothetical, but that it shows that witness Moore's proposed disallowance is incorrect even if his suggested course of action were possible, which it was not. Tr. Vol. 24, pp. 103-05.

Witness Kerin also disagreed with witness Moore's contention that DEC should have chosen Weatherspoon over Buck as a beneficiation site, and with the recommendation that $10,612,592 associated with beneficiation costs at Buck be disallowed. N.C. Gen. Stat. § 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. Witness Kerin maintained that in keeping with the timing requirements imposed by CAMA, Duke Energy identified Buck, H.F. Lee, and Cape Fear as the three beneficiation sites based on its conclusion that they offered the most feasible alternative and the best economic value to customers while complying with CAMA. While he agreed that reuse of ash at Weatherspoon is appropriate, and noted that the Company is selling Weatherspoon ash for reuse today, he disagreed that Weatherspoon was a possible choice for one of the three beneficiation sites required by CAMA. Tr. Vol. 24, pp. 93, 105-08, 131.

Witness Kerin explained that witness Moore mixes apples and oranges by contending that by selecting Buck as a beneficiation site and therefore supplying an additional 300,000 tons per year of CCR material to the concrete industry, the Company in turn reduced demand for the 70,000 tons per year of CCR material for the same purposes from Weatherspoon for which Duke Energy was unable to find a purchaser. He explained that Weatherspoon ash is sold under contract to cement manufacturers and is used as raw material or aggregate in the manufacture of cement, while beneficiated ash from Buck is used as a replacement for cement in concrete. Because these are separate products that are used for different purposes, the sale of beneficiated ash from Buck has no impact on the demand for ash from Weatherspoon. Tr. Vol. 24, pp. 105-06.

Witness Kerin maintained further that witness Moore's assertion that choosing Buck increased closure costs at that site compared to other closure options misses several key facts that support the decision to select Buck as the third beneficiation site. He noted that Weatherspoon contains only 2.4 million tons of ash, which is approximately one-third the 6.4 million tons at Buck, and that the Company reasonably considered the amount of ash available at the site, and the potential uses for the ash when making decision to invest in beneficiation at a particular location. Witness Kerin also maintained that Weatherspoon is in a poor geographic location in relation to the major markets for ash used in the cement industry. He explained that since trucking the ash is part of the cost of the sales, with its proximity to Charlotte and Greensboro, Buck is in a much better location for beneficiation, and has the highest revenue projection, followed by Cape Fear (Greensboro and Raleigh) and H.F. Lee (eastern North Carolina and Virginia). Witness Kerin noted further that, even after issuing an RFP, Duke Energy has only been able to secure a buyer willing to enter into a long-term contract for 230,000 tons of ash from Weatherspoon, but not the additional 70,000 tons to qualify the site for beneficiation. He also asserted that the statute's specific references to installation and operation of an ash beneficiation project and production indicates the General Assembly's intent that Duke Energy construct and operate technology such as carbon burn-out plants and STAR technology, rather than use the basic drying and screening operations occurring at Weatherspoon. Tr. Vol. 24, pp. 106-07.

Witness Kerin also disputed witness Moore's recommendation that the Commission disallow recovery of $2,000,100 related to DEC's purchase of nine adjacent parcels at Cliffside. He stated that witness Moore's conclusion ignores one of the Commission's and DEC's core policies, which is to encourage and promote harmony between public utilities, their users and the environment. He also noted that the cost of the Cliffside parcels was not included in the costs the Company is seeking to recover in this case, and has never been part of the Company's ARO and as such the recommended disallowance of these costs should not be granted. Tr. Vol. 24, pp. 93, 108.

Witness Kerin also objected to witness Moore's suggestion that the $489,000 in costs to ship ash from Riverbend to Homer, Georgia should be disallowed on the basis that the ash could have been shipped to DEC's Marshall Steam Station. Witness Kerin testified that shipping ash to Homer, Georgia was a reasonable, temporary solution that allowed DEC to begin required ash excavation within the mandatory time frame after Riverbend received its NPDES stormwater permit. He explained that the Company sent Riverbend ash to Marshall once that site became available, but that Marshall was not an available location in May 2015, when the Company began trucking ash from Riverbend pursuant to DEQ directives. Those directives, as contained in an August 13, 2014, letter from DEQ, requested that Duke Energy submit an excavation plan for Riverbend by November 15, 2014, and that it begin removing ash at Riverbend within 60 days of receiving DEQ approvals to do so, which included an NPDES Stormwater Permit. Since DEQ issued the permit on May 15, 2015, DEC had until July 15, 2015, to begin excavating Riverbend ash. He stated that while the Company was exploring long-term options to receive the Riverbend ash, it was still obligated to meet this deadline, and thus it was imperative that the Company find someone to haul and dispose of the Riverbend ash on a short turnaround. Waste Management National Services, Inc. (Waste Management) was able to meet that requirement, and began trucking ash from Riverbend on May 21, 2015, and transported the final load on September 18, 2015 (as opposed to February 2016, as asserted by witness Moore). DEQ approved Duke Energy's request to dispose Riverbend ash at Marshall on June 19, 2015, which did not allow enough time for the Company to accomplish all of the tasks required to utilize Marshall and still meet the 60-day deadline. Once those tasks were accomplished, DEC did begin transporting Riverbend ash to Marshall on July 22, 2015, seven days after DEQ's excavation deadline. Tr. Vol. 24, pp. 93, 108-10, 131-32.

Witness Kerin also clarified that DEC could not have stopped trucking Riverbend ash to the R&B Landfill once it began trucking to Marshall, as the Company was under contract with Waste Management to dispose of the ash at R&B for 17 weeks, or through September 18, 2015, and would have been in breach of contract if it had halted the ash transport before that date. He also stated that the Company's decision to enter into a 17-week contract was based on several factors, including the short turnaround needed for a contractor to truck and accept the ash, and the knowledge that this would be a temporary disposal site and resulting need to find a contractor willing to accept a limited tonnage of ash. Tr. Vol. 24, pp. 110-11.

Finally, witness Kerin noted that Public Staff witness Garrett agreed with the Company that the Inactive Ash Basin and the Old Ash Fill at W.S. Lee needed to be excavated. Witness Kerin disagreed, however, with witness Garrett's assertion that DEC should have delayed excavation of ash material from the Inactive Ash Basin (IAB) and Old Ash Fill at W.S. Lee in order to undertake a grading and slope stabilization project, excavate the overly steep sections of the IAB berm, and dispose of that ash on-site. Witness Kerin testified that this approach would not have been reasonable or prudent and therefore disagreed with witness Garrett's recommendation that the costs associated with transferring ash to Brickhaven ($27,275,192) should be disallowed. Tr. Vol. 24, pp. 93, 111-12, 132.

Witness Kerin testified that, consistent with a Consent Agreement entered into by Duke Energy and the SCDHEC in September 2014, which required excavation of the IAB, the Company excavated ash from this basin and trucked it to the solid waste landfill operated by Waste Management in Homer, Georgia. He explained that, based on available stability analysis, the IAB did not meet the required CCR Rule dam safety factors for maximum storage pool and liquefaction conditions. He concluded that it was therefore reasonable and prudent for DEC to begin excavation immediately. Witness Kerin also noted that at the time the Company was deciding how to manage the IAB, its priority was to address stability and erosion concerns on the river frontage along the IAB dike. He asserted that, due to the low safety factors of the IAB dike, the Company was already limiting equipment access on the dike crests, which limited work to the very narrow portion of downslope area that extended from the dike toe to the river's edge. Witness Kerin asserted further that the equipment necessary to implement witness Garrett's proposal could not have safety traversed the dike on the downslope, and that moving the heavy equipment to the downstream/river side of the downslope would have created undue risk to bank stability and unnecessarily risked worker safety. In addition, while the Company evaluated interim measures that could offer stability and risk mitigation during excavation, these involved work at and in the river to both access and install the features, and the Company decided not to pursue these measures due to the time needed to obtain a USACE permit for work in the river. He noted that the Company had already initiated the IAB's excavation and that by the anticipated 12-month time period to obtain the permit and 4-6 months to install the required features, the basin would be nearly excavated, and the Company would have to later remove the features to restore the river. Witness Kerin maintained that witness Garrett's proposed two-phased approach would not address these issues, would have unnecessarily put worker and environmental safety at risk, and the delay would have been unacceptable to DEC and to the SCDHEC. Tr. Vol. 24, pp. 112-14, 132.

Witness Kerin disagreed with witness Garrett that the Company should have agreed to different terms in the Consent Agreement with SCDHEC. He explained that, based on SCDHEC's expressed concerns, the deadlines agreed to pursuant to the Consent Agreement were reasonable and allowed the Company to achieve the primary goal of the agreement, which was to excavate ash. SCDHEC's concerns were driven by the IAB abutting the Saluda River and the resulting risk of river impacts, the steepness of the banks, and the heavily wooded nature of the slope. He stated that SCDHEC wanted Duke Energy to take prompt action with respect to excavating the IAB, and that desire is reflected in the Consent Agreement and excavation deadlines. Tr. Vol. 24, p. 115.

Witness Kerin also disagreed with witness Garrett that the Company should have delayed excavation of the Old Ash Fill, noting that the Old Ash Fill was also subject to the Consent Agreement and that the SCDHEC was as adamant that the Company excavate this site immediately as it was with regard to the IAB. Tr. Vol. 24, p. 116.

Finally, witness Kerin testified in response to witness Garrett's criticism of DEC's plan to excavate the Structural Fill Area at W.S. Lee in the future, even though witness Garrett did not suggest any disallowances with respect to this plan. Witness Kerin stated that, in order to resolve the concerns of SCDHEC and environmental groups, the Company agreed to mitigate the future risk of operating two ash management structures by managing all ash at W.S. Lee through a single management structure – the landfill – as opposed to taking a piecemeal approach as suggested by witness Garrett. He stated that if the Company was later required to excavate the Structural Fill area after the landfill project was completed, it would incur greater costs than it will incur by managing the ash while the landfill project is ongoing, and that the decision to excavate this area now is reasonable and prudent approach to mitigating against potential future ash related liability and to reduce future costs for the site. Tr. Vol. 24, pp. 93, 116.

Witness Kerin also testified that Public Staff witness Junis' testimony, similar to witness Lucas in the DEP case, incorrectly asserts that the costs of groundwater treatment wells installed at Belews Creek would not have been incurred absent the Sutton Settlement. Witness Kerin asserted that this conclusion ignores the fact that, while the measures undertaken at Belews Creek were reflected in the Sutton Settlement, they were moved up in time from when they would have otherwise been required, and DEC would have installed extraction wells in order to comply with CAMA even without the Sutton Settlement. Tr. Vol. 24, p. 117.

He also disagreed with witness Junis' contention that the Company should not recover the cost of equipment that could remove selenium at Riverbend. He stated that witness Junis' recommendation does not reflect the reality of managing that facility either at the time of that purchase or at present. He explained that in order to excavate the Riverbend ash, as required by CAMA, DEC had to dewater the impoundments, and that the interstitial water treatment system for the dewatering process was designed to meet NPDES permit limits, including selenium. The environmental consultant hired by the Company to develop this treatment system, WesTech, proposed the SeaHAWK bioreactor system for this purpose. Witness Kerin contended that it was imperative for the Company to have a treatment system that could appropriately treat the site's wastewater and meet future permit selenium limits. He stated that, while the SeaHAWK is important to the Company for staying within its permit limits, it is expensive to operate (approximately $60,000/month), and that the Company will only use it when other physical and chemical extraction methods are insufficient. Witness Kerin emphasized, however, the prudency of having this system in place should it be needed, in order to avoid the need to cease ash removal operations in the case that selenium levels increased and the bioreactor was not on site. He offered the example of a five-month delay to secure a bioreactor would cost the Company several million dollars in delay charges under its contract with Charah. He concluded that it was reasonable and prudent for DEC to purchase a bioreactor system to mitigate against potential violations of NPDES permit limits and to treat decanted wastewater at Riverbend, and that the recommended disallowance of those costs should therefore be rejected. Tr. Vol. 24, pp. 90, 117-19, 132.

Witness Kerin also rebutted AGO witness Wittliff's assertion that the Commission should disallow the Company's coal ash costs, and noted that witness Wittliff's testimony appears to go even further in this case than his recommended disallowance in the DEP case. Witness Kerin testified that witness Wittliff's testimony, with its revisionist history approach to coal ash management and his inability to specify or quantify specific disallowances, is not useful to the Commission. Tr. Vol. 24, pp. 91, 133.

Witness Kerin testified that AGO witness Wittliff's contentions that DEC's management of coal ash has lagged behind the rest of the utility industry, and that the Company has ignored dam safety at its facilities, are incorrect. He asserted that DEC's ash management practices have conformed and evolved with changes in industry practices and regulatory standards. He noted that witness Wittliff based his assertion that the Company knew by 2008 that impoundments were no longer the industry standard in part on excerpts from Duke Energy's 10-K filings around that time. He stated that these excerpts, which pertain to Duke Energy and not to individual utilities like DEC, simply notify the Securities and Exchange Commission of potentially significant coal ash costs that Duke Energy anticipated at that time, and potential new regulatory contingencies to which it could become subject, but were not intended to analyze DEC's coal ash management practices and do not support witness Wittliff's claim that the Company's coal ash management practices were out of step with industry or that the Company knew of any such inconsistency. Witness Kerin also stated that while the 1988 and 1999 EPA Reports cited by witness Wittliff in support of his position show increases in the percentages of new lined landfills and surface impoundments, witness Wittliff acknowledged that the Company last constructed a new ash basin in 1982. In addition, while these reports show an increase in the percentage of basins that were lined from 17 to 28% between 1975 and 1995, 28% is still a minority of new basins being constructed, which is consistent with DEC's practice during this time frame. Witness Kerin stated further that witness Wittliff's assertion fails to account for site-specific conditions, which as the EPA explains in the preamble to the CCR Rule and guidance, is an essential consideration when making CCR unit-specific determinations. Finally, he pointed out that witness Wittliff presented no credible evidence to show that the Company's engineering and design of its impoundments was not consistent with industry practice and regulatory requirements at the time. Tr. Vol. 24, pp. 119-21.

Witness Kerin also rebutted witness Wittliff's assertion that DEC should have built new lined impoundments as opposed to expanding existing unlined impoundments. He testified that witness Wittliff's argument ignores the fact that construction of new lined impoundments would have entailed significant expense to the Company, while not removing the need to maintain existing unlined impoundments. In addition, because such action would have occurred before it was consistent with industry standards, it would have put the Company at risk of disallowance of those costs. Witness Kerin stated that the suggestion that DEC chose not to construct new lined impoundments in order to delay and avoid potential exposure to requirements for more rigorous environmental standards is therefore not only unfounded but also inconsistent with the realities of managing coal ash basins. He noted that, at the hearing in the DEP proceeding, witness Wittliff admitted that the majority of utilities in the country continued to use unlined, wet ash impoundments well after the timeframe in which he alleges the Company should have ceased to do so, because the law allowed them to do it, and the law continued to allow them to do it. Witness Kerin noted the inconsistency between admitting that the Company's use of unlined, wet basins was legal and in line with most utilities in this country, and asserting that DEC was imprudent by doing so. Tr. Vol. 24, pp. 121-22.

Witness Kerin also responded to witness Wittliff's contention that dam safety has not been a priority for the Company, and stated that DEC has a very robust dam safety program, led by a central organization with responsibilities for each site in the system. The program includes weekly documented inspections, and tracking of any corrective actions, as well as episodic inspections to be conducted following heavy rain events or certain seismic events. He stated that the Company also conducts detailed, documented annual inspections of each facility, and that any issues identified are tracked through to resolution. He noted in addition that the Company internally inspects and documents basin discharge piping annually, and again tracks identified issues through to resolution. Any required modifications are managed through a stringent program including plans and specifications submitted to and approved by DEQ's Dam Safety Program. This is all in addition to DEQ's own annual inspections of the basins and all completed modification projects. He stated that the Company provided five-year dam safety inspections dating to the 1970s. He maintained that no instance arose in which the Company failed to act upon a major dam safety issue. He argued that subsequent mentions of certain issues simply show that DEC was monitoring the condition before identifying or confirming the need for longer- term repair, and that these inspections do not show any major issue that threatened the integrity of the dam's ability to retain the ash in the basin. Tr. Vol. 24, pp. 122-24.

Witness Kerin responded to witness Wittliff's criticism of witness Kerin's own CCR experience and qualifications to discuss ash management industry standards, noting the irony of witness Wittliff's position in light of his own limited experience in this area. Tr. Vol. 24, p. 124.

Witness Kerin also testified that, like his testimony in the DEP case, CUCA witness O'Donnell's analysis and recommendation of a 75% disallowance of the Company's coal ash costs relies on multiple analytical flaws that are fatal to his conclusion, and that witness O'Donnell made little effort to address those flaws in his conclusions from the earlier case. Specifically, witness Kerin disagreed with witness O'Donnell's conclusion that his national comparison of CCR assets retirement obligation, or ARO, amounts shows that the Company's ARO is overstated by 75%. He stated that witness O'Donnell appears not to have considered 23 factors that must be accounted for in order to seriously attempt this type of analysis. He also stated that witness O'Donnell made no attempt to quantify DEC's coal ash AROs resulting from CAMA, as compared to its obligations under the CCR Rule, or to determine the impetus for coal ash AROs for the other utilities to which he compares the Company. Witness Kerin argued that witness O'Donnell cannot credibly testify that the Company's ARO coal ash costs are higher because of CAMA when he cannot attribute any specific ARO coal ash costs to CAMA or attribute ARO coal ash costs for other companies to any particular regulatory obligation. He explained that, even if witness O'Donnell had conducted such an analysis, it would not provide an accurate comparison, because other utilities are in very different stages of their coal ash management timeline than DEC. Witness Kerin also maintained that the SNL data relied upon by witness O'Donnell are rough estimates, and that there is substantial uncertainty over the level of actual closure costs for many of those utilities he listed. Witness Kerin therefore recommended that the Commission consider the reasonableness of the Company's ARO amount on its own merits, based on the facts of this case, and without regard to witness O'Donnell's proposal. Tr. Vol. 24, pp. 90, 125-28, 133.

Finally, witness Kerin disagreed with Sierra Club witness Quarles' assertions as to the consistency of DEC's coal ash management practices with industry, the costs of lined landfills as compared to surface impoundments, and Duke Energy's previous pursuits of reuse options for ash. Tr. Vol. 24, p. 91. For the same reasons he presented in response to witness Wittliff's testimony, witness Kerin disagreed with witness Quarles' conclusion that operation of unlined basins after the 1980s was unreasonable, and countered that witness Quarles does not appear to have considered industry standards or regulatory requirements or, like witness Wittliff, to have presented any specific evidence that the Company's impoundment engineering and design was not consistent with industry practice and regulatory requirements at the time. He also testified that witness Quarles' assertion that closure costs for surface impoundments were higher than costs for lined landfills fails to consider the additional costs associated with conversion to lined landfills, in addition to the fact that DEC last constructed a new basin in 1982. Finally, witness Kerin clarified that the Company did make sales of coal ash for reuse during the 1980s, from Marshall in 1986 and Belews Creek in 1988, contrary to witness Quarles' assertion otherwise. Tr. Vol. 24, pp. 128-29, 133-34.

2. Wright

On rebuttal, Company witness Wright testified to several issues related to the recovery of costs associated with coal ash remediation expenses raised in the testimonies of Public Staff witnesses Garrett, Moore, Junis, and Maness, AGO witness Wittliff, and CUCA witness O'Donnell. He stated that, overall, the theories underlying these witnesses' recommended disallowances of these costs are unfounded, do not provide a proper basis on which costs may be disallowed, and should be rejected by the Commission. Tr. Vol. 12, pp. 156-2-3, 161-62.

Witness Wright first disagreed with Public Staff witness Junis' recommendation to disallow approximately 49% of the Company's remaining coal ash costs after accounting for certain other disallowances that he and Public Staff witnesses Garrett and Moore recommend. Witness Wright stated that this recommendation does not align with the appropriate regulatory standard for denial of cost recovery, which he explained is a finding that specifically identified costs are imprudent or unreasonable. He noted that witness Junis did not find the Company imprudent for most of the coal ash-related cost, nor did witness Junis find the Company's costs to be unreasonable. Instead, witness Wright explained, witness Junis 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. Witness Wright maintained that it is not proper for the Commission to deny cost recovery based on speculation of future findings of violation, or to impose a sharing of costs based upon an undefined culpability standard. Tr. Vol. 12, pp. 156-4, 162-63.

Witness Wright also explained that the proposed sharing of cost is 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, he recalled, Dominion requested a recovery of CCR Rule compliance costs up to and through 2016. He explained that those expenditures included closure and related costs for the Chesapeake Energy Center, even though a court found past violations of the Clean Water Act at this location. He stated that 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. He stated his opinion that the CCR cost recovery methodology applied in the Dominion case was correct and should be applied in the same way for DEC. Tr. Vol. 12, pp. 156-12, 163.

Witness Wright also testified that 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. He explained that the Commission has found abandoned nuclear cost not to be used and useful, and thus not eligible for rate-based treatment. In contrast, he noted, 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. He stated that 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. Tr. Vol. 12, p. 156-16 – 156-19.

Witness Wright proceeded to state that the Commission's treatment of environmental cleanup of manufactured natural gas (MNG) plants also does not support the Public Staff's proposed cost sharing, and referred to his direct testimony that MNG 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. In addition, he noted that MNG facilities, like abandoned nuclear plants, were found not to be used and useful. He noted further that there is 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. Tr. Vol. 12, p. 156-18.

Witness Wright also testified that the 25-year amortization period proposed by the Public Staff is not justified by their cost sharing theory, which is based on a culpability theory and by defining these costs as being extremely large. He explained that 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. He explained further that it could also result in a perception of the State's utilities as riskier, leading to higher cost of capital and cost of service. Tr. Vol. 12, p. 156-22.

Witness Wright disagreed with witnesses who claimed that Duke Energy substantially caused the CCR Rule and CAMA and that, therefore, all costs incurred to comply with these requirements should be disallowed. He referenced his direct testimony that while the timing of CAMA may have been influenced by the Dan River accident, he cannot conclude that the North Carolina legislature would have adopted a different substantive law without Dan River. He noted in addition that 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. He also noted that state-specific actions to address CCRs have been adopted in a number of jurisdictions. Based on all these factors, he opined that North Carolina likely would have adopted a state-specific CCR regulation regardless of the Dan River accident. Tr. Vol. 12, pp. 156-24 – 156-27, 163-64.

Witness Wright also argued that CAMA was not intended to be a punitive law. He stressed that CAMA does not contain any punitive limitation on cost recovery except for the provision for certain spills to surface water. He also noted that 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. He stated that the General Assembly has shown that it will, when it wants to, adopt specific cost recovery restrictions with other state environmental laws, as exemplified by the Clean Smokestacks Act. In contrast, he explained, 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 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. Tr. Vol. 12, pp. 156-28 – 156-31, 164-65.

With regard to coal ash litigation costs, witness Wright reiterated that DEC has excluded from its recovery request all fines, penalties, and fees related to the Dan River accident. Tr. Vol. 12, p. 156. He also opined, however, that witness Junis' apparent position that all of the Company's costs to defend lawsuits should be disallowed recovery, regardless of whether the Company is ultimately found liable or not, is not supported by precedent or sound regulatory policy. First, the Glendale Water case does not support this theory. In addition, he noted that the Commission has recognized that settlements and litigation defense costs, when reasonable and prudent, are recoverable costs, and that the Commission and the Public Staff have also recognized that settlements are beneficial. Tr. Vol. 12, pp. 156-31 – 156-36, 165.

Witness Wright disagreed with the Public Staff's recommendation of provisional cost recovery for coal ash expenditures prudently incurred from January 2015 through August 2017, based on the argument that the appropriateness of such recovery may depend on the outcome of legal determinations. He noted first that this would appear to be retroactive ratemaking. He also stated that the standard is that 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. Tr. Vol. 12, pp. 156-39 – 156-40, 165.

Additionally, witness Wright disagreed with Junis' recommendation that costs to remedy environmental violations where the costs exceed what CAMA would have required be disallowed, including those specifically related to Belews Creek groundwater extraction and treatment and a second related Riverbend selenium removal. Witness Wright, citing to his earlier testimony, stated first, that absent a finding that the Company was guilty or had liability associated with environmental issues that led to additional compliance costs, or that the settlement in question Junis was citing to was imprudent, that environmental costs like the Belews Creek costs noted here should be recovered from ratepayers and not shareholders. Secondly, in regard to Junis' statements that DEC had a duty to comply with groundwater rules, and its failure to comply are a reason to deny the recovery of these costs with or without settlement, witness Wright cited his earlier testimony where he discusses how and why unlined coal ash pond exceedances occur and are not unexpected. Moreover, witness Wright noted his earlier testimony in explaining why witness Junis' theory that DEC had a duty to comply with the North Carolina groundwater rules, Title 15A, Subchapter 2L of the North Carolina Administrative Code (2L rules), without regard to whether it followed accepted industry practices, is misplaced. Tr. Vol. 12, pp. 156-36 – 156-38, 162.

Next, witness Wright stated that he disagreed with CUCA witness O'Donnell's belief that the DEC was responsible for the passage of CAMA and should be responsible for any coal ash costs above that required by the CCR Rule, and cited to his earlier statements disagreeing with such. Witness Wright opined that the Commission should reject witness O'Donnell's recommendation that the Company's environmental compliance costs should be disallowed based on a comparison of the alleged national asset retirement obligations, or ARO, amounts relating to CCRs. He stated further that witness O'Donnell's analysis neither considered the fact that most utilities are behind DEC from a timing perspective in both planning and addressing coal ash pond closure, nor reflected the most recent coal ash CCR costs being reported by various electric utilities. Witness Wright also disagreed with witness O'Donnell's statement that the EPA's reconsideration of aspects of its CCR Rule "direct[ly] conflict[s]" with witness Wright's statements about this country's ever-tightening environmental standards. Witness Wright stated that although it was possible that the EPA could modify its current rule, there is no way for DEC to know if, when, or how such modification might occur. Tr. Vol. 12, p. 156-40 – 156-43.

Finally, witness Wright testified that the Commission should reject AGO witness Wittliff's recommendation that because the Company had a "history" of regulatory violations, and due to the Dan River accident leading to the enactment of CAMA, DEC should be disallowed recovery of coal ash related costs. In reference to his earlier statements on CAMA and his direct testimony, witness Wright reiterated his belief that the North Carolina legislature would have adopted some type of state specific coal ash closure legislation shortly after the passage of CCR, regardless of the Dan River accident. He noted that witness Wittliff did not quantify the disallowance he recommends, but instead assumed that the costs incurred to comply with both the Federal CCR rules and CAMA were unreasonable or imprudent without any underlying support. Additionally, witness Wright identified that witness Wittliff's recommended disallowance was also at odds with his testimony filed in the DEP case. Tr. Vol. 12, pp. 156-43 – 156-44, 163-64.

At the hearing, witness Wright explained in response to questions by counsel for the Sierra Club that, if the Commission approved the Company's request for recovery of ongoing expenses, the Company would then bring its actual costs to the Commission for review and approval annually. Tr. Vol. 12, p. 186. Witness Wright also explained in response to questions regarding EPRI documents from the 1980s that those reports acknowledged that more information was being provided about potential impacts from coal ash, but that the reports also advised that disposal procedures not yet be modified. Id. at 191-92. During cross by counsel for NC WARN, he discussed the decision tree that the Commission uses to determine whether costs are recoverable and how that recovery will occur. Witness Wright explained that the first question is whether the costs were reasonable and prudent in providing service to ratepayers and, if so, the next question is whether they were used and useful and, if so, the last stage is to consider what outcome would be fair and equitable. Witness Wright explained further that it is at the last stage where the Commission has leeway to consider different rate designs to achieve a fair and equitable result. Id. at 202-06.

Witness Wright testified in response to questions by counsel for the Public Staff that the fact that DEC has an exceedance or even a violation is not indicative or necessarily tied to the recoverability of costs DEC is seeking in this case. Witness Wright explained that if DEC has a violation and admitted wrongdoing, or an adjudicated proceeding determined there was wrongdoing, those costs or fines should not be recovered. Witness Wright testified that that is different from DEC having to now comply with new standards; in terms of costs associated with new obligations, he considers those long-term compliance costs. Tr. Vol. 13, pp. 77-78, 91-93. On redirect, witness Wright agreed that it is reasonable to assume that state and federal regulators who understood how soil and water interact with each other would have passed appropriate rules and regulations over time to account for that interaction. Tr. Vol. 13, pp. 95-96.

In response to questions by the Chairman, witness Wright confirmed that, in his opinion, the Commission's primary responsibility pertains to cost recovery rather than regulating how utilities implement state and federal environmental laws, and agreed that DEQ was the agency in charge of approving coal ash remediation plans. Witness Wright also agreed that the Commission is not a court of general jurisdiction, and that it determines the reasonableness and prudence of utility decisions rather than make cost recovery decisions by following a duty of care or any other standard available in tort or other type of law. Witness Wright confirmed that this standard does not consider what could or should be anticipated into the future, but considers what is reasonable and prudent given the information known now. Tr. Vol. 13, pp. 99-102.

3. Wells

Company witness Wells testified on rebuttal to the different approach taken by the Public Staff in this case from the DEP case. In the DEP case, the Public Staff attempted to characterize DEP's compliance with its NPDES permits as poor. In this case, witness Junis did not discuss DEC's compliance with NPDES permit requirements, which witness Wells noted has been outstanding, but rather suggested that the existence of seepage at the Company's CCR impoundments is evidence of the Company's "culpability." Witness Wells explained that the Public Staff's position ignores (1) the fact that the EPA first directed permitting authorities to address seeps in 2010, (2) the Company's attempts to obtain regulatory certainty as to seeps, and (3) DEQ's challenges in implementing EPA's direction. Tr. Vol. 24, p. 226.

Witness Wells testified that Public Staff witness Junis' negative characterization of DEC's compliance record is not justified by the historical record. Tr. Vol. 24, p. 224. He explained that exceedances of groundwater standards and the existence of seeps in the vicinity of the Company's ash basins do not indicate mismanagement or poor compliance programs. Witness Wells stated that the existence of groundwater exceedances at or beyond the compliance boundaries at DEC sites is rather a function of where these sites are on the timeline of groundwater assessment and corrective action under modern laws that have changed the way unlined basins are viewed. Witness Wells testified that the Company's decision to use unlined basins to treat ash transport water was reasonable and consistent with the approach consistently employed across the power industry at the time that the basins were built. Witness Wells noted that each DEC site had been properly and legally operating an unlined basin for at least a decade before the adoption of any regulatory requirements related to groundwater corrective action. Witness Wells noted further that as requirements changed over time, DEC has taken every action required by DEQ's groundwater rules, and later by CAMA and the federal CCR Rule, to address groundwater impacts as they have been identified. Tr. Vol. 24, pp. 227-29, 236, 258.

Witness Wells opposed the suggestion that DEC only engaged in comprehensive groundwater monitoring and remediation when forced to do so by CAMA and other developments. He explained that the Company began monitoring groundwater at Allen in 1978, Belews Creek and Marshall in 1989, Dan River and W.S. Lee Steam Stations in 1993, and the remaining sites in or around 2006. He noted that, in 2011, DEQ prescribed a process to be undertaken by DEQ and utilities upon the identification of a groundwater exceedance near a coal ash pond, which included performance of an assessment to determine the cause of the exceedance and, as necessary, develop a Corrective Action Plan consistent with North Carolina groundwater rules. He stated that under that process, only after a utility failed to undertake corrective action when directed to do so would DEQ consider pursuing enforcement. He noted that, contrary to witness Junis' testimony, all of this activity predates the threat of litigation by environmental groups, the DEQ enforcement suit, the Dan River spill, and CAMA. He also testified that, as witness Junis' testimony and exhibits demonstrate, DEC has always promptly responded to any concerns raised by the relevant regulatory entities and where necessary, implemented appropriate corrective action steps to remedy any issue. He stated that the Company has proactively sought consent orders and written agreements to ensure alignment with the regulatory agency as to appropriate scope and timing of additional investigation and corrective action. Tr. Vol. 24, pp. 230-31, 234-36, 259-60.

Witness Wells disagreed with witness Junis' apparent contention that DEC should have moved well ahead of accepted science, regulatory requirements, and industry practice and begun taking measures to prevent any and all groundwater quality issues without regard to the cost of those measures or whether sufficient and proven technology existed at the time to address the conditions at the site. He explained that the papers cited by witnesses Junis, Wittliff, and Quarles discussing potential issues associated with coal ash disposal, and the importance of developing and implementing appropriate controls, highlight the evolving state of knowledge regarding the risks and best practices related to coal ash disposal management, rather than condemn the use of unlined basins. Tr. Vol. 24, pp. 232-34, 258-59.

Witness Wells also testified that North Carolina's groundwater laws were not intended, as witness Junis contends, to be punitive. While he agreed that the groundwater rules require corrective action without regard to fault, he disagreed with witness Junis' conclusion that responsibility for corrective action is equivalent to any other violation of the law. He stated that the record in this case clearly demonstrates that groundwater contamination resulted from DEC's otherwise lawful use of unlined ash basins in furtherance of its mission to provide low cost electricity, and that the use of ash basins was an accepted and reasonable practice conducted with DEQ and EPA oversight. He explained that, for historical sites such as those at issue in this case, this State's groundwater regulations and the DEQ's practices and policies, as well as the CCR Rule, are focused on environmental protection rather than culpability, that the required corrective action is based upon science and not an assessment of wrongdoing. He stated that, in evaluating Corrective Action Plans, DEQ considers numerous factors, including the extent of any threat to human health or safety, impact on the environment, available technology, potential for natural degradation of the contaminants, and cost and benefits of restoration. He concluded that, if the utility cooperates with DEQ, the applicable law and policies are designed to drive corrective action rather than enforcement action, and he saw no intent for those law and policies to be used to deny cost recovery in regulatory proceedings. Tr. Vol. 24, pp. 237-38, 260.

Witness Wells also stated that witness Junis' characterization of groundwater violations under the 2L rules ignores the iterative nature of comprehensive site assessment. He noted that measuring exceedances at different locations in a plume around an activity may result in multiple exceedances of groundwater standards, but that measurement does not result in multiple violations of the 2L rule's prohibition. He explained that this distinction is important for evaluating the claim that the number of exceedances indicates a "breadth of environmental violations." He stated that it would be more accurate to say that, at seven sites, DEC has lawfully operated ash basins that, after decades of use, resulted in exceedances of groundwater standards at those sites. He pointed out how Duke Energy's coal ash basins are some of the most studied sites in North Carolina, with more than 1,400 groundwater monitoring wells, and that the number of exceedances presented by witness Junis signifies therefore the thoroughness of the evaluation rather than a number of groundwater violations. Tr. Vol. 24, pp. 238-40, 260-61.

Witness Wells also explained that the extraction and treatment activity required by the Sutton Settlement, which costs witness Junis recommends for disallowance, is work that the Company simply agreed to perform earlier than required under the CCR Rule and CAMA in order to address offsite groundwater impacts. Tr. Vol. 24, pp. 241, 260.

Witness Wells also disagreed with witness Junis that the amount of litigation regarding the Company's ash basins suggests that the Company was imprudent in managing ash. He opined that the amount of litigation has been driven by nongovernmental organizations that have been pressing for complete excavation of ash from all basins across the Southeast. He stated that DEC has appropriately been opposed to this, arguing instead that final closure methods should be dictated by the CAMA process and a site-specific balancing of net environmental benefits of various closure options based on science, regulatory policy, and the best interest of the Company's customers. He stated that the positions of the NGOs and the suits do not themselves indicate imprudence. Rather, he explained, the appropriate closure methodology must take into consideration the particular characteristics of each site. He stated that the EPA and North Carolina agree and that, consistent with this principle DEC has settled cases where science and engineering supported closure by excavation, and continues to vigorously litigate cases where other closure methods are more or equally protective of the environment at less cost. He concluded that the volume of filed litigation on its own should not factor into the Commission's determination of whether the Company's CCR costs were prudently incurred. Tr. Vol. 24, pp. 242-44.

Witness Wells also disagreed with the Public Staff's suggestion that any exceedance or violation of water quality regulations, no matter how minor or how long ago, leads to the denial of cost recovery for any activity that acts to "cure" the impacts of the violation. He reiterated that not all exceedances of the 2L standards amount to a violation that requires corrective action under the 2L rules. He also stated that even when an exceedance requires corrective action, the groundwater rules do not treat the exceedance the same way as, for example, the Clean Water Act treats an exceedance of an NPDES permit limit. When the latter is violated, he explained, the permittee is immediately subject to a notice of violation (NOV) and penalty, and must ensure the next discharge complies with the permit limit or risks a new NOV and escalating penalty. He contrasted this with groundwater standards, under which an exceedance does not immediately result in an NOV and penalty. Instead, he explained the owner/operator must report the exceedance and work with DEQ to determine whether it was due to permitted activity, assess the extent of the exceedance, and undertake corrective action. Any newly measured exceedances do not require a further site assessment and do not result in additional or escalating penalties, but are actually expected as additional assessment prior to corrective action is conducted. He testified that the 2L Rules' corrective action provisions are deliberately designed around the idea that older facilities, built before liners were a regulatory obligation, were likely to have associated groundwater impacts, that such impacts were not the result of regulatory noncompliance, and that they should be addressed in a measured process. He concluded that compliance with this process is not mismanagement and should not be held against DEC with respect to cost recovery. Tr. Vol. 24, pp. 244-46.

Witness Wells also addressed seeps. He explained that all earthen impoundments seep, and that DEQ's dam safety regulations acknowledge this. He stated that EPA first directed permitting authorities to address seeps in 2010, and at that time, the Company engaged DEQ to determine the appropriate approach to address seeps and began including them in permit applications. He asserted that DEQ did not consider seeps to have a significant environmental impact. He also maintained that EPA and DEQ did not appear to agree on the appropriate approach to address seeps. He maintained that, absent the CCR Rule or CAMA, the existence of seeps in a basin would not on its own automatically trigger basin closure and should not, therefore, impact the Company's ability to recover its CCR environmental compliance costs. He asserted that, although closing basins would be one way to address seeps, it would be the most drastic of several possible remedies, and both EPA and DEQ have stated that seeps can be addressed by permitting or rerouting, among other options. Tr. Vol. 24, pp. 246-50, 261.

Accordingly, Witness Wells explained, DEC entered into a special order by consent (SOC) with DEQ to address seeps at the Allen, Marshall, and Rogers (formerly Cliffside) stations. He explained that the SOC provides regulatory clarity and certainty as to the appropriate monitoring frequency, parameters to be sampled and limits with respect to the non-engineered seeps, while requiring the Company to accelerate the schedule for decanting water from the basins, a process that is expected to substantially reduce or eliminate seeps. He further testified that DEC is working with DEQ to develop additional SOCs based on this model to address non-engineered seeps at the remainder of DEC's and DEP's impoundments. He clarified that the SOC requirements to accelerate decanting do not create additional costs for the Company over and above the cost to complete these activities in compliance with CAMA and the CCR Rule. In sum, witness Wells testified that the application for and execution of SOCs to address seeps is not evidence of DEC "culpability," but rather a regulatory mechanism to provide clarity and alignment with respect to scope and schedule for compliance-related activities given a change in circumstances, such as a change in requirements or in operations. Tr. Vol. 24, pp. 251-53, 261.

Finally, witness Wells disagreed with witness Junis' suggestion that DEC caused the creation and adoption of the CCR Rule. He testified that the environmental regulatory regime is an ever-evolving body of law, and the EPA engaged in more than two decades of studies before it finally issued a proposed CCR Rule in 2010. Through this process, he noted, the EPA identified 150 cases in over 20 states involving over 25 utilities and government facilities that involved groundwater damage with at least a potential link to coal ash, but determined that immediately closing basins, which would require shutting down operating coal plants, would be more harmful than taking a measured approach. Tr. Vol. 24, pp. 254-55, 261-62.

At the hearing, in responding to questions by counsel for the Sierra Club, witness Wells responded that the Company did engage in voluntary analysis of its coal ash sites prior to DEQ requirements to do so, as far back as the 1970s at Allen, and determined based on those analyses that no significant impacts to groundwater were occurring, and no significant risk to groundwater going forward. Tr. Vol. 25, pp. 36-37.

In response to questions by the Commission, witness Wells confirmed that while the AGO and Public Staff presented documents in this case addressing the Company's actions going back to the 1950s, the AGO took no action itself with regard to coal ash management until 2014, when the AGO became involved with citizen suits. He opined that the reason for that inaction was that the Company's actions with regard to coal ash were acceptable from a regulatory perspective until much more recently. Tr. Vol. 26, pp. 72-73. He also stated that DEC's recent comprehensive studies of the groundwater surrounding the Company's ash basins conducted pursuant to CAMA have confirmed that, while groundwater has been impacted, there is no evidence of any current or likely future impacts to, for example, off-site drinking wells or other receptors at any of the seven sites, and have validated the Company's measured approach to coal ash management in previous years. Id. at 77-80. He confirmed that the Company currently has installed wastewater treatment equipment where needed at all of its basins to comply with CAMA. Id. at 82-83.

In response to questions by the Chairman, he further confirmed that, absent other considerations, there are a number of remedies to address a seep that could be applied rather than to excavate the basin. Tr. Vol. 26, pp. 85-88. He also stated that substances such as iron, manganese, and pH are classified by the EPA as secondary maximum contaminant levels which are regulated based on aesthetics (e.g., taste, odor, etc.) and are not considered health risks. Witness Wells acknowledged that some recent studies have suggested that exposure to extremely high levels of manganese could pose a health risk, but explained that, typically, those levels are orders of magnitude above where the limit was set for aesthetic purposes. Id. at 88-91. Finally, he addressed the difficulty of monitoring groundwater impacts, especially when dealing with naturally occurring elements, and explained that a single monitoring well is a snapshot of that particular area at that point in time, and that conditions 100 yards away could be very different, yet still be naturally occurring. He stated that this is why the Company's efforts to monitor a large area is an iterative process. Id. at 91-93.

4. McManeus

On rebuttal, witness McManeus responded to witness Maness' proposed adjustments regarding coal ash pond closure costs. She explained that there were two main adjustments, to remove ongoing environmental costs and adjust deferred environmental costs, as listed in Boswell Exhibit 1, Schedule 1, and based upon seven specific adjustments proposed by witness Maness. Witness McManeus explained that although the Company disagrees with the majority of the Public Staff's seven proposed adjustments, it does not disagree with witness Maness' third or fourth adjustments. Witness Maness' third adjustment is to add a return on the deferred balance up through the expected date of new rates in this proceeding. The fourth adjustment is to calculate the return using a mid-month convention rather than a beginning-of-month convention. Tr. Vol. 6, pp. 312-14, 357-58.

In regard to witness Maness' second adjustment recommending that the costs DEC has identified as "CAMA only" be allocated based on an allocator that allocates to all jurisdictions, witness McManeus explained that the Company has identified very specific cost categories that should be treated as an exception to the general allocation rule that costs of a system be borne by all of the users of the system. Witness McManeus explained that these costs are unique to North Carolina and that such an exception is consistent with other examples where the Commission has allowed direct assignment to North Carolina, and cited to the cost allocation methods used in regard to the North Carolina Renewable Energy and Energy Efficiency Standard and the Clean Smokestacks Act. Witness McManeus further explained that the Company disagreed with witness

Maness' first, fifth, sixth, and seventh proposed adjustments, and that such adjustments were addressed by other Company witnesses' testimony. Tr. Vol. 6, pp. 312-16, 357-58.

Witness McManeus rebutted the Public Staff's recommendation to exclude the deferred coal ash balance from rate base, and indicated that, to the contrary, it was appropriate for that balance to remain in rate base and for the Company to earn a return on it. She indicated that while witness Doss approached this issue from an accounting perspective, from her viewpoint it was important to recognize that rate base represents the amount of funds supplied by investors. Such funds have been advanced for many purposes, including construction of electric plant, but, she stated, there are other purposes as well – for example, to purchase fuel inventory or to provide cash working capital, etc. Tr. Vol. 6, p. 317. In this particular case, she indicated, investors have advanced funds to pay for coal ash compliance costs, and it is therefore appropriate for the Company to be allowed a return on the deferred coal ash balance during the period for which the Company will amortize and collect these amounts from its customers, as the Company will continue to incur financing costs on the balance of funds that is uncollected. Id. She added that the characteristic that makes the deferred coal ash cost a legitimate component of rate base is the fact that the funds used to pay those costs were supplied by investors. Id. at 318.

Lastly, witness McManeus addressed witness Maness' statement that expenses of operating and maintaining property in rate base in the present or in the future "are allowed to be recovered from the ratepayers on an ongoing basis as operating expenses." Agreeing with his statement, she explained that this is the principle underlying the Company's proposal for recovery of the ongoing annual coal ash basin closure costs, what witness Maness terms the "run rate." Witness McManeus stated that these ongoing compliance costs are no different from other ongoing and recurring expenses the Company incurs in the test year, and that such costs are equivalent to the Company's reasonable and prudent test year coal ash basin closure spend. She further explained how the Company's proposed recovery of these ongoing compliance costs through rates would be subject to true-up in subsequent rate cases so that only actual costs are recovered. In conclusion, witness McManeus cited to Chairman Finley's statements in the recent DEP rate case proceeding that a rider could be an alternative mechanism for cost recovery of on-going compliance costs, and stated that the Company agrees that a rider would be an appropriate alternative mechanism to recover such costs. Tr. Vol. 6, pp. 315-16, 357-58.

5. Doss

Witness Doss rebutted the Public Staff's positions regarding ARO accounting that the Company employed for its deferred coal ash compliance costs, and, in particular, witness Maness' characterization of those costs as a deferred expense. Witness Doss provided a detailed explanation of the GAAP and FERC accounting rules with respect to the ARO established in connection with the Company's coal ash basin closure obligations, as well as the deferral orders issued by the Commission in Docket No. E-7, Sub 723. Tr. Vol 12, pp. 61-71. He noted that the Company had simply accounted for these costs as required under GAAP and FERC Uniform System of Accounts, and had deferred the impacts of ARO accounting, as authorized by the Commission's deferral orders. Id. at 70-71.

Witness Doss also responded to witness Maness' opinion that coal ash costs should not be classified as "used and useful" costs. He indicated that, to the contrary, under GAAP and FERC accounting guidance, the asset created when a Company initially recognizes an ARO is considered part of the property, plant and equipment for the assets which must be eventually retired. Id. at 71. He noted further that such costs are used and useful in that they are intended to provide utility service in the present or in the future through achieving their intended purpose: environmental compliance, the retirement of the ash impoundments and the final storage location for the residuals from the generation of electricity, and that the achievement of those three purposes is used and useful as the utility has the obligation to comply with CAMA and the CCR Rule. Id. at 73.

Commission Determinations

General Cost Recovery Principles

A central operating principle underlying utility rate regulation in North Carolina (and virtually all other jurisdictions) is that the utility's costs are recoverable in rates. As two of the leading modern commentators on utility regulation put it in the opening paragraphs to a chapter (titled "The Role of the Revenue Requirement") in their treatise on utility regulation:

> No firm can operate as a charity and withstand the rigors of the marketplace. To survive, any firm must take in sufficient revenues from customers to pay its bills and provide its investors with a reasonable expectation of profit …. Regulated firms are no exception. They face the same constraints ….
>
> A basic concept underlying all forms of economic regulation is that a regulated firm must have the opportunity to recover its costs. … Without the opportunity to recover all of its costs and earn a reasonable return, no regulated private company can attract the capital necessary to operate.

Jonathan A. Lesser & Leonardo R. Giacchino, Fundamentals of Utility Regulation 39 (Pub. Utils. Reports, Inc., ed., 2007) (Lesser & Giacchino).

Lesser & Giacchino refers to the concept of cost recovery as the "revenue requirement" (id.), and the North Carolina Supreme Court has also acknowledged its central role in utility ratemaking. See, e.g., State ex rel. Utils. Comm'n v. Thornburg, 325 N.C. 484, 490, 385 S.E.2d 463, 466 (1989) (Thornburg II) and State ex rel. Utils. Comm'n v. Thornburg, 325 N.C. 463, 467 n.2, 385 S.E.2d 451, 453 n.2 (1989) (Thornburg I), in which the concept is stated to be embedded in the statutory rate making formula, and, indeed, expressed formulaically:

> This statute [N.C. Gen. Stat. § 62-133] requires the Commission to determine the utility's rate base (RB), its reasonable operating expenses (OE), and a fair rate of return on the company's capital investment (RR). These three components are then combined according to a formula which can be expressed as follows:
>
> (RB x RR) + OE = REVENUE REQUIREMENT

Costs are not recoverable simply because they are incurred by the utility. The utility must show that the costs it seeks to recover are (1) "known and measurable"; (2) "reasonable and prudent"; and (3) where included in rate base "used and useful" in the provision of service to customers. Lesser & Giacchino, at 41-43. But once it has shown that these metrics are met, the utility should have the opportunity to recover the costs so incurred. This is what North Carolina's ratemaking statute requires (<u>see</u> N.C. Gen. Stat. § 62-133(b)(5)), and to do otherwise would amount to an unconstitutional taking.

In this case, no party has questioned whether the coal ash basin closure costs for which the Company seeks recovery are "known and measurable"; indeed, the Company documented these costs and has shown that they were in fact incurred. Rather, the arguments raised by Intervenors challenging the inclusion of the Company's coal ash basin closure costs in rates center on whether those costs are "reasonable and prudent" and whether they are "used and useful." These concepts have been framed by this Commission and the North Carolina Supreme Court.

A. <u>Reasonable and Prudent</u>

The seminal treatment of "reasonable and prudent" costs is this Commission's order entered in Docket No. E-2, Sub 537 (the 1988 DEP Rate Case), in which the Commission approved with some exceptions costs the Company incurred in connection with the construction of Unit 1 of the Shearon Harris nuclear plant. See 1988 DEP Rate Order. The Commission there articulated the following principles governing the question of "reasonable and prudent":

First, the standard for judging prudence is "whether management decisions were made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or reasonably should have been known at that time. … [T]his standard … must be based on a contemporaneous view of the action or decision under question. Perfection is not required. Hindsight analysis – the judging of events based on subsequent developments – is not permitted." 1988 DEP Rate Order, p. 14.

Second, challenging prudence requires a detailed and fact intensive analysis, and the challenger is required to (1) identify specific and discrete instances of imprudence; (2)

demonstrate the existence of prudent alternatives; and (3) quantify the effects by calculating imprudently incurred costs. Specifically,

- A decision cannot be imprudent if it represents the only feasible way to accomplish a necessary goal.
- The Commission can only disallow imprudent expenditures – that is, actions (even if imprudent) with no economic impact upon customers are of no consequence. Thus, identification of an imprudent action or inaction is not by itself sufficient; rather, there must be a demonstration of the economic impact.
- The proper amount chargeable to customers is what the expenditure would have been absent the imprudent acts or decisions of management.

Id. at 15. The North Carolina Supreme Court upheld the Commission's prudence determination. See Thornburg II, 325 N.C. at 489, 385 S.E.2d at 466 (finding "no error" in that portion of the Commission's decision).

B. Used and Useful

"Used and useful" is a concept directly embedded in the ratemaking statute – N.C. Gen. Stat. § 62-133(b)(1) states that 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, less that portion of the cost which has been consumed by previous use recovered by depreciation expense …." In general, the Supreme Court's treatment of the concept has been in the negative, i.e., asserting as a basis for its decision that something is not "used and useful" – for example, excess common facilities are not "used and useful" as a matter of law, see Thornburg II, 325 N.C. at 495-96, 385 S.E.2d at 469, and a water treatment plant that was not in service as of the end of the test year and would never again be in service was not "used and useful" within the meaning of N.C. Gen. Stat. § 62-133(b)(1). State ex rel. Utils. Comm'n v. Carolina Water Serv., Inc., 335 N.C. 493, 508, 439 S.E.2d 127, 135 (1994). The reverse, of course, is that if the expenditures do support and provide service to customers, the costs are "used and useful."

C. Burden of Proof

The Commission must address arguments on the burden of proof. DEC argues that it incurred the CCR remediation costs at issue, meeting its prima facie burden and that Intervenors have failed to justify discrete disallowances. The AGO argues DEC bore the burden of quantifying the disallowances the AGO deems appropriate. DEC argues that the substantive standard is imprudence. Others argue that the standard is one of due care. The CCR remediation costs DEC seeks to recover in this docket and that are being challenged by Intervenors consist of 2015-2017 costs to dewater, remove, and transport CCRs from unlined repositories and store them in lined ones or to install caps. DEC incurs these costs pursuant to requirements of EPA CCR Rule and North Carolina CAMA provisions or other requirements of DEQ. In compliance with this Commission's authorization, these costs have been accounted for in an Asset Retirement Obligation account and have been deferred to permit appropriate ratemaking treatment in this case.

The AGO argues that DEC should bear the burden to disprove why disallowances to its 2015-2017 CCR remediation costs should not be accepted.

> The AGO does not agree that the factors the Commission found appropriate for an approach taken by an independent auditor in the 1988 DEP Order should have been applied in the 2018 DEP Rate Order as a prudence framework, and similarly in this general rate case, the prudence framework is inappropriate because it essentially puts the burden of proof on intervenors, contrary to settled law. As the Commission observed in the 2018 DEP Order, because costs are site-specific, establishing a past cost would be a "near impossibility." 2018 DEP Order p. 200. As discussed in detail in Part I.B below, there is extensive affirmative evidence that Duke's imprudent management of coal ash disposal and coal ash sites, and its delays in addressing known problems, have driven up the costs now being incurred and have shifted the costs onto future customers unfairly. It is not appropriate to require ratepayers to prove that costs are unrecoverable; rather it is up to Duke to prove that some or all of the detailed costs are not attributable to the poor history of operations; that prudent alternatives that would have reduced the costs were not available when problems became known; and that these factors support the reasonableness of the costs Duke seeks to recover.

AGO's Brief, pp. 9-10.

The AGO cites no authority for this argument, nor does it argue that cases and precedent relied upon by DEC and the Commission in the 2018 DEP case to the contrary are wrongly decided or should be ignored. While asserting that the Commission's reliance on established evidentiary principles in the 2018 DEP case is "contrary to law," the AGO cites no authority to back up its assertion. The AGO asserts in response to DEC's petition to recover 2015-2017 CCR remediation costs -- costs no party asserts DEC did not incur -- that these costs should be disallowed due to DEC's imprudence in years prior to 2015. These are the AGO's allegations, not DEC's. The AGO's novel theory that a petitioner should bear the burden to disprove Intervenor allegations unsupported by evidence is one the Commission does not accept. The AGO's theory of its case, at least in its brief, appears to be that if DEC had acted to remediate CCR disposal and storage issues in years prior to 2015, DEC's costs would have been lower, so the 2015-2017 costs are excessive. To prevail, the AGO must quantify what the costs of the actions not taken should have been. The AGO argues DEC failed to act appropriately before 2015. DEC cannot be expected to provide costs of acts not taken. The AGO has not undertaken this task.

While some of the costs to comply with the requirements of environmental regulators are challenged by Intervenors as excessive, i.e., unreasonable, most of the costs being challenged are questioned on the theory that DEC is in breach of a standard classified as a "duty to exercise due care." The challenge equates failure to meet a due care standard with management imprudence. According to this theory, even though no environmental regulatory requirement imposed a duty to remove CCRs from unlined impoundments before EPA CCR rules or CAMA, management was imprudent in not doing so. The challenge does not address DEC's decisions to initially place the CCRs in unlined impoundments between 1945 and 1982, but its failure to remove the CCRs thereafter or alternatively to cease to sluice CCRs to these unlined impoundments at a time when trends within the industry suggested that leachate finding its way into groundwater from the bottom of the unlined repositories posed potential risks to the environment and human health.

The Commission has not been cited any case to support the theory that, in determining the recovery through utility rates, costs of environmental remediation incurred by management to comply with express requirements of environmental regulators, management's decisions should be assessed against a standard of due care. The Commission's duty is not to determine liability to and assess damages for torts committed by management for injury to the environment or to receptors of contaminants. Environmental regulators and courts of general jurisdiction are the appropriate arbitrators of those disputes. DEC's unlined impoundments at issue operated pursuant to environmental permits as wastewater treatment facilities by DEQ or its predecessor. That agency's statutory mandate is environmental protection and would be the agency to rectify a breach of a duty of due care, if any, such as that advocated by certain Intervenors in this case. The issue before this economic regulatory tribunal is imprudence - who should bear the remediation costs - the utility's stockholders or its consumers and on the basis of what justification.

According to the U.S. Supreme Court:

> Good faith is to be presumed on the part of managers of a business. … In the absence of showing of inefficiency or improvidence, a court will not substitute its judgment for theirs as to the measure of a prudent outlay.

West Ohio Gas Co. v. Ohio Pub. Utils. Comm'n., 294 U.S. 63, 72, 55 S. Ct. 316, 321 (1935).

In a case cited with favor in Priest, Principles of Public Utility Regulation:[57]

> Only where affirmative evidence is offered challenging the reasonableness of the operating expenses incurred, on the grounds that they are exorbitant, unnecessary, wasteful, extravagant, or incurred in the abuse of discretion or in bad faith, or are of a nonrecurring character not likely to recur in the

[57] A.J.G. Priest, Principles of Public Utility Regulation 1969, Vol. I, pp. 422-23.

future, has the commission a reasonable discretion to disallow any part of the expenses actually incurred.

Alabama Pub. Serv. Comm'n v. Southern Bell Tel. & Tel. Co., 253 Ala. 1, 42 So.2d 655, 674 (1949) cited with approval, State ex rel. Utils. Comm'n. v. Intervenor Residents, 305 N.C. 62, 77, 286 S.E.2d 770, 779 (1982).

This standard against which costs recovery challenges are measured has elements qualitatively and quantitatively distinct and more rigorous than a tort standard of due care. The expert witnesses sponsored in this case failed to support allegations of discrete actions constituting imprudence. For its equitable sharing disallowance, the Public Staff proceeded on an equitable sharing theory, not on a theory of imprudence. AGO witness Wittliff on cross-examination failed to show what DEC should have done differently to remediate CCR, when it should have acted, and what the cost of such alternative conduct should have been. While AGO witness Wittliff filed forceful allegations on paper in the prehearing filings, much as was the case in the DEP rate hearing, his support of that testimony from the stand on cross examination was not persuasive.[58] Public Staff witness Junis likewise could not identify costs DEC would have incurred to remediate prior to 2015.[59] Without record evidence from parties advocating disallowances

[58] Q. Beginning on line 16, you state, "However, when it came to making changes to its own unlined surface impoundments, the Company chose not to move forward with the industry, but instead chose to add more and more coal ash to the unlined impoundments despite the longstanding seepage and groundwater issues at its facilities."

Did I read that correctly?

A. You did.

Q. Mr. Wittliff, despite your 30 years of experience as an engineer, I am correct, am I not, that if I look through the entirety of your testimony in this case and all of your exhibits, I will not find any engineering analysis of what exactly that DEC should have done, when it should have done it, where it should have done it, and how much it would have cost with respect to the lines in the testimony that I just read you, will I?

A. Say that again, please.

Q. Yes, sir. You make a contention, on page 10 of your testimony, on line 17 through 20 that I just read, alleging that DEC chose not to move forward with the industry, but instead chose to move more and more coal ash to unlined impoundments.

My question is, if I want to look at how I should have moved forward with the industry, where I should have done it, when I should have done it, how much it should have cost me - and by "me," I'm referring to DEC - I cannot find those answers anywhere in your prefiled testimony, can I?

A. No.

Tr. Vol. 11, pp. 283-84

[59] "The coal ash-related environmental violations have a cost. Corrective actions to address environmental impacts under CAMA and the Environmental Protection Agency's (EPA) Coal Combustion Residuals Final Rule (CCR Rule), including ultimately closure of all DEC ash basins, will remedy the environmental violations. Therefore, it is not feasible to identify all the costs that would have been incurred to remedy violations under the pre-existing environmental regulations and laws, such as 15A NCAC 02L (2L rules) and North Carolina General Statute 143-215.1, if CAMA and the CCR Rule were not in effect. . . . There is no doubt that substantial assessment and remedial costs would have been incurred without CAMA and the CCR Rule, but, in my opinion, those costs cannot be quantified without undue speculation."

Tr. Vol. 26, pp. 646-47

for failure to take CCR remediation steps prior to 2015 pursuant to the burden of proof theory or an unsupported "failure to exercise due care standard" of what action DEC should have taken, when it should have acted, and what the costs would have been, the Commission cannot approve such specific disallowances. Attempts to identify years-old hypothetical past costs, for example, by allocating tons of CCRs to formulate inexact allocation percentages to be applied to 2015-2017 costs is to rely upon guesswork that simply is legally and equitably deficient.[60]

Coal ash located within basins above levels saturated by water and unaffected by the contours of the bottom of the impoundment can be removed at a cost lower than coal at lower levels. Costs of replacement repositories will vary depending on land costs, location, regulatory requirements and site preparation costs. Transportation costs will vary depending on distance, market conditions, regulatory requirements and timing of incurrence.

Efforts to identify what DEC should have done prior to EPA CCR and CAMA, when it should have done so and what the costs should have been even with the benefit of 20/20 hindsight pose insurmountable obstacles. CCR remediation even under the supervision of NC DEQ is a site-specific undertaking with procedures that have evolved over time and continue to do so. Without statutory or regulatory standards and guidelines to follow, no one can say what the prudent course would have been even if one acts on the assumption that DEC was imprudent to await promulgation of the definitive environmental regulatory requirements.

Under EPA CCR regulations and CAMA requirements, the prevalent remediation remedy is dewatering, excavation and removal or cap-in-place. These explicit, express requirements depend heavily on NC DEQ oversight and supervision. The remediation steps must be completed in compliance with deadlines and substantial collaboration between NC DEQ and DEC with respect to permitting. Compliance will occur as far into the future as 2028. No one can predict today how compliance will be accomplished or what these future compliance costs will be. The decision by NC DEQ on whether cap-in-place for eligible impoundments versus CCR removal has yet to be made. Yet Intervenors ask the Commission to look backward where the regulatory requirements were not in place and therefore unknown and speculate what it would have cost to comply so as to impose the imprudence disallowance. Having failed to even attempt to quantify such a disallowance, Intervenors' theory is without probative support and must be rejected.

Without any requirement such as EPA CCR rules or CAMA to remediate CCRs stored in unlined pits simply because unlined pits posed "potential" threats to the environment, Intervenors must "pick a date" when in their opinion such remediation should have been undertaken. Likewise, Intervenors apparently assume the remediation

[60] When quantifying quantities of CCR for purposes of cap-in-place, utilities rely upon linear measurements, not tonnage.

remedy would have been dewatering, excavation and removal or perhaps cap-in-place, even though they do not agree on which of these alternatives is appropriate for each basin. No support for this assumption exists. Without requirements such as those of EPA CCRs and CAMA, DEC logically would have attempted to investigate each unlined repository to determine insofar as possible the extent to which contamination was occurring or had the potential to occur. Absent evidence of actual or probable future contamination, DEC would have been remiss in spending millions of dollars to remediate or to choose the most expensive remediation alternative.

As to impoundments where contamination was occurring or potentially would occur, remedies far short of complete excavation such as installing water extraction methods beyond the impoundment to remove water or to excavate contaminated soil were available and arguably should have been employed as a least cost solution.

Any CCR impoundment leaks, whether lined or unlined. The underlying soil composition and subsurface groundwater flow direction for each site are significant considerations in assessing risk of harmful contamination from CCR constituents. Piedmont red clay acts as a natural sealant. Unless CCR contaminants in excess of proscribed levels migrate beyond boundaries outside repositories, no actionable threat occurs. Monitoring wells provide tools to measure migration of harmful constituents. Determinations of naturally occurring levels of CCR contaminants must be made to determine whether measurements in excess of published standards, if any, originate at the impoundment.

Determining the number and placement of monitoring wells, not an inexpensive endeavor (Tr. Vol. 26, p. 92), is an inexact science. The prevalent and cost-effective process is to install monitoring wells iteratively to best identify harmful groundwater contamination. Tr. Vol. 26, pp. 92-93. Evidence of excessive constituent levels up gradient of impoundments tells nothing about impoundment contamination but is necessary to identify naturally occurring constituents that may or may not exist down gradient. Unlike synthetic contaminants like dry cleaning fluid or nuclear waste where evidence of its presence in groundwater can be tied to a source of pollution, all the potentially harmful elements from coal ash occur naturally in the ambient environment. Tr. Vol. 26, pp. 92-93. Underground water flows may dissipate excessive levels of CCR contaminants through natural attenuation to those below standard thresholds. There may be no receptors in the vicinity of the impoundment.

The best evidence of the difficulty in determining what DEC should have done, when it should have done so and what the cost should have been prior to 2015 is the significant dispute that arises in this case over what DEC should have done, when it should have done so and what the costs should be with respect to the actual 2015-2017 costs. DEC actually has incurred these costs in its efforts to comply with EPA CCR and CAMA published standards and requirements undertaken under NC DEQ's supervision and guidance. Parties to this case hotly dispute where replacement repositories should be constructed, when and how CCRs should have been transported, and which CCRs should have been designated for beneficial reuse.

Consequently, the Commission determines that efforts to recreate the past as no party has been able to do so is a fruitless endeavor that the Commission is unable and unwilling to undertake.

Additional complications to certain Intervenors' theory that disallowances to 2015-2017 CCR remediation costs should be made because DEC failed to begin remediation or alternative CCR storage earlier magnify the fatal flaw in the theory. From an accounting cost recovery perspective, the Commission authorizes establishment of an ARO, defers costs for remediation, and later amortizes these deferred costs over five years. DEC began to incur the remediation costs in 2015 and will continue to do so under EPA CCR and CAMA regimes until 2028. Consequently, under procedures being followed, cost recovery will occur through 2033. If, under certain Intervenors' theory, DEC should have begun remediation in 2006 (hypothetically, because Intervenors cannot identify the starting date under their theory), DEC would still have been incurring CCR remediation costs during the test year and would have been amortizing CCR remediation costs from prior years. Consequently, ratepayers paying rates established in this case could very well face the possibility of being no better off under Intervenors' alternative, unsubstantiated theory. Perhaps, arguably, DEC should have established a coal ash remediation cost ARO earlier in anticipation of a future requirement to undertake remediation efforts, and costs not so accounted for should be disallowed. However, the Commission's practice is not only to approve the establishment of the ARO but to defer the costs accounted for in the ARO for later recovery in a general rate case. Theories relied upon to recreate the past based on hypothetical scenarios all depend on guesswork and subjective factual constructs that are beyond the ratemaking standards this Commission must employ.

The burden of proof to show that rates are just and reasonable is always on the utility. See N.C. Gen. Stat. § 62-134(c). Intervenors, however, have a burden of production in the event that they dispute an aspect of the utility's prima facie case. See, e.g., State ex rel. Utils. Comm'n v. Conservation Council, 312 N.C. 59, 64, 320 S.E.2d 679, 683 (1984) (utility's costs are "presumed to be reasonable" unless challenged); State ex rel. Utils. Comm'n v. Intervenor Residents of Bent Creek/Mt. Carmel Subdivisions, 305 N.C. 62, 76-77, 286 S.E.2d 770, 779 (1982) ("The burden of going forward with evidence of reasonableness and justness arises only when the Commission requires it or affirmative evidence is offered by a party to the proceeding that challenges the reasonableness of expenses…."). If the Intervenor meets its burden of production, the ultimate burden of persuasion reverts to the utility, in accordance with N.C. Gen. Stat. § 62-134(c).

The Commission has consistently followed this shifting burden framework. See, e.g., DEC Remand Order, (Docket No. E-2, Sub 1142) p. 34. In practice this means that Intervenors may not rest merely on arguments and theories, they must adduce actual evidence challenging some aspect of the Company's cost recovery case. Further, that evidence must support the Intervenor's challenge under the substantive standard established by North Carolina law. Evidence predicated on 20/20 hindsight is insufficient to effectuate a prudence challenge, inasmuch as the substantive prudence standard forbids hindsight analysis.

D. Conclusion with respect to January 1, 2015 - December 31, 2017 Costs

The Commission determines that the Company has met its burden – both the prima facie burden of production and the ultimate burden of persuasion – of showing that the coal ash basin closure costs it actually incurred from January 1, 2015 through December 31, 2017 are recoverable and that a return, but one reduced to recognize a mismanagement penalty, is warranted, and that the Commission with contrasting evidence on the merits, with exception addressed below, authorizes recovery.

First, Company witness Kerin demonstrated that the Company's coal ash management historical practices (i.e., pre-CCR Rule and pre-CAMA) have generally comported with industry practices and then-applicable regulations, especially in this region of the country. See, e.g., Tr. Vol. 14, pp. 99-100, 135. The Commission determines that compliance with industry standards is an important but not the sole criterion in determining the recoverability of CCR remediation costs. As part of his work to bring DEC into compliance with the new CCR Rule and CAMA, witness Kerin helped establish and participated in an industry peer group consisting of representatives of, for example, Dominion and Southern Company, and his interaction with that group and his investigation of practices at other Duke Energy Corporation-affiliated utilities confirm his conclusion that the Company's practice was not out of line with the overall industry practice. Id. at 96-97. As witness Kerin testified, when he looked at all of the practices at the Duke Energy Corporation utilities, in multiple states, "Indiana, Ohio, North Carolina, South Carolina, and Florida, all those practices were the same, so that led me to believe that all those [companies], prior to becoming Duke Energy companies, were managing their ash and their ash basins in the same manner." Id. at 158-59. He made the same observation concerning the peer group of companies – AEP, Dominion, the Southern Companies and TVA – and "their practices were similar." Id. at 159. He concluded: "So that whole group of states across the eastern part of the United States, we were operating our basins in the same fashion." Id.

Witness Kerin's testimony on this point was not seriously or credibly controverted by any Intervenor. Indeed, AGO witness Wittliff was not able to specify exactly how the Company should have acted differently in managing its coal ash to be consistent with industry, at which sites it should have taken those actions, and how much those actions would have cost the Company. Tr. Vol. 11, pp. 283-89. Witness Wittliff also presented no credible evidence showing DEC's engineering and design of its impoundments was not consistent with industry practice and regulatory requirements at the time other than his own, subjective allegations. Tr. Vol. 24, p. 121.

Moreover, key documents that Intervenors used in cross-examination in an effort to rebut witness Kerin's testimony contain provisions that in part support, to some extent at least, his testimony and these findings. For example:

- Los Alamos Laboratory Report (1979): "Much of the ash produced by coal ash combustion is discharged into ash ponds." Sierra Club – Kerin Cross Ex. 3, p. 6.
- EPRI Coal Ash Disposal Manual (1981): No coal ash was landfilled in either North or South Carolina; rather, all of it was stored in ponds. Sierra Club – Kerin Cross Ex. 4, Table 3-1, pp. 3-7. Further, 81% of the coal ash produced in the Southeast was placed in ponds. Id. at 3-8.
- EPA Report to Congress (1988): This Report (Sierra Club – Kerin Cross Ex. 5) confirms that the Company's disposal of coal ash in ponds conformed in large measure to industry practice. The Report refers to ponds as "surface impoundments" Id. at 4-11, and notes that CCR waste management practices varied by region, and that in the South (EPA Region 4, which includes North and South Carolina) 95% of the plants manage their CCRs on-site. Id. at 4-23. The Report continues, "On-site management is common because utilities in this region often use surface impoundments, which are typically located at the power plant." Id. It noted further that "access to abundant, inexpensive supplies of water … [in Region 4] often made it economical to use this management option." Id. at 4-20.

The 1988 EPA Report also indicates that "until recently, most surface impoundments and landfills used for utility waste management have been simple unlined systems," and that "liner use has been increasing in recent years." Id. at 4-33. Intervenors point to these statements to argue that the Company's continued use of unlined ponds was outside standard industry practice and is otherwise imprudent. The Commission disagrees. The Report notes, for example, that 87% of surface impoundments were unlined (id. at 4-33), and that neither North Carolina nor South Carolina required liners. Id. at 4-3. It also notes that one-fifth of waste generated by coal-fired power plants was reused, and "the remaining four-fifths are typically disposed in surface impoundments or landfills." Id. at ES-2. The Report thus validates witness Kerin's testimony that "unlined basins were the industry standard" at that time. Tr. Vol. 24, pp. 128-29. As he stated, "the EPA report focused on new landfills and surface impoundments, while DEC last constructed a new ash basin in 1982." Id. at 129 (emphasis in original). This was six years before the EPA Report was submitted to Congress. As witness Kerin stated further, in the DEP case AGO witness Wittliff testified that the majority of utilities continued to use unlined wet ash impoundments even after this timeframe, "because '[t]he law allowed them to do it, and the law continued to allow them to do it.'" Id. at 122. Finally, witness Kerin's conclusion is supported by the preamble to the CCR Rule itself. See Public Staff Kerin Cross-Examination Ex. 4.

Based upon similar evidence in the DEP case, the Commission found that "[s]ince the 1950s, standard industry practice at least in the Southeast, has been to deposit in coal ash basins, and such basins were constructed and used at all of the Company's coal-fired generating units." 2018 DEP Rate Order, p. 142. This finding and witness Kerin's testimony are also consistent with the Commission's findings in the 2016 DNCP Rate Order: "DNCP, like many electric utilities in the United States, has for decades generated electricity by burning coal. During those decades, the widely accepted reasonable and prudent method for handling CCRs has been to place them in coal ash landfills or ponds (repositories)." 2016 DNCP Rate Order, p. 60.

It is undisputed that there will be a natural flow from an unlined basin into groundwater. This is a function of basic science. Tr. Vol. 13, p. 58. As Company witness Wells testified:

> Earthen basins and dike walls are prone to the movement of liquid through porous features within those structures through a process known as seepage. Such seepage is common, and, to a degree, is necessary to maintain the stability of an earthen dam or dike wall; otherwise they become saturated, which may reduce margins of safety with respect to their structural integrity.

Tr. Vol. 24, p. 246. Accordingly, seepage from the Company's unlined ash basins – basins that complied with industry standards and the then-applicable regulatory requirements – is part of the "normal operation" of the basins. This evidence of the Company's historical compliance establishes that, except in limited fashion, its past coal ash management practices did not cause it to incur in the January 1, 2015 – December 31, 2017 timeframe unjustified costs to comply with current laws and regulations. Tr. Vol. 14, pp. 100-01.

Second, witness Kerin's testimony established that in large measure the costs were reasonable and prudent. In light of the evidentiary presumptions and shifting burden of production and persuasion, and based on the Commission's assessment of the credibility of the witnesses opining on the facts and policy considerations at issue, the Commission relies heavily on his testimony. The testimony of other Company witnesses, including witness Wells, will be discussed in greater detail in the sections of this order dealing with the Public Staff's specific disallowance recommendations. Witness Kerin's testimony was credible, demonstrated command of the subject matter (he testified, after all, that he had "lived" with that "company-specific subject matter every day for the past four years" (Tr. Vol. 24, p. 92), and the Commission determined in the 2018 DEP Rate Order that he has "'lived' this project since its inception," (2018 DEP Rate Order, p. 187), and the Commission concludes that his conclusions were not dislodged after being subjected to vigorous cross-examination.

Third, witness Kerin's testimony establishes that the capitalized costs for which the Company seeks recovery are eligible for a return and, at least to the extent they are capital in nature, were used and useful. These costs were expended to comply with the CCR Rule and CAMA, along with consent agreements that require the Company to implement corrective actions consistent with either or both of those regulatory requirements. Tr. Vol. 14, p. 115. Capital expenditures undertaken to enable compliance with the law qualify as "used and useful," in that the Company does not have the option to fail to comply, and, as indicated in the testimony of Company witness Wright, are routinely recoverable in rates. Tr. Vol. 14, p. 115; Tr. Vol. 12, p. 131. Further, witness Kerin's testimony (see Tr. Vol. 14, p. 135 and Kerin Ex. 10 and Ex. 11) details the "core components" of the costs incurred. These include, for example:

- With respect to the Allen and Belews Creek Plants' coal ash basins, oversight and environmental health and safety (EHS) activities, engineering and basin closure projects;
- With respect to the Buck Plant's coal ash basins, EHS activities, basin closure costs, mobilization and beneficiation costs;
- With respect to the Cliffside Plant's coal ash basins, mobilization and infrastructure costs, water management, ash processing, basin support projects, inspections and maintenance, and EHS activities;
- With respect to the Dan River Plant's coal ash basins, mobilization and infrastructure costs, water management, ash processing, landfill construction, engineering closure costs, and EHS activities;
- With respect to the Marshall Plant's coal ash basins, EHS activities, inspections and maintenance;
- With respect to the Riverbend Plant's coal ash basins, ash processing, water management, and EHS activities; and
- With respect to the W.S. Lee Plant's coal ash basins, mobilization, ash processing, and engineering closure plans.

Witness Kerin testified further that mandated closure of the existing coal ash basins meant that the modifications had to be made to their associated power plants, so as to direct storm water flow away from the ash basins and to cease bottom ash and fly ash sluice flow to the basins. Tr. Vol. 14, p. 133. In addition, other process streams must be directed away from the coal ash basins to facilitate de-watering and closure. Id.

Witness Kerin and his supporting exhibits describe costs expended to facilitate the Company's handling and storage of coal ash, so as to conform to the new legal requirements imposed on the Company resulting from the promulgation of the CCR Rule and the passage of CAMA. DEC is subject to these new legal requirements and must handle and store coal ash in a manner that complies with them. As such, except as detailed below, the capital costs of compliance are "used and useful," and the Company is authorized to recover them along with other costs accounted for in the ARO, along with a return as adjusted below on its outlay of these funds.

1. Intervenor Challenges to Cost Recovery

Intervenors have mounted challenges to the Company's recovery (with a return) of its already-incurred coal ash basin closure costs on two levels. First, in a manner that departs from the prudence framework the Commission established in the 1988 DEP Rate Case, the AGO, through witness Wittliff; CUCA, through witness O'Donnell; and the Public Staff, through witness Maness, all advocate that costs be disallowed even without a detailed analysis of the specific costs the Company has submitted for recovery.[61] Second, the Public Staff (and only the Public Staff) proposes to disallow specific costs incurred through the testimony of witnesses Garrett and Moore, and Junis, thus at least attempting to follow the Commission's prudence framework.

However, the Commission determines that these approaches are not appropriate, and these proposed specific disallowances are not approved.

2. AGO/CUCA Approach: The Company "Caused" CAMA

At the hearing, in response to questions by counsel for the Company, witness Wittliff admitted that, while his testimony stated that he would support a Commission finding that the coal ash costs incurred by DEC were unreasonable and imprudent, his actual position is that the Company should be able to recover its costs to comply with the CCR Rule, but nothing more. Tr. Vol. 11, pp. 279-81. He stated that costs incurred by the Company to comply with the CCR Rule are reasonable and prudent. Id. at 282-83. In contradiction to its witness, the AGO in its brief asserted that all the CCR cost recovery DEC seeks in this case is imprudent. Not only has the AGO been unable to quantify the costs DEC should have incurred prior to 2015, it has failed to sponsor a witness that can support its theory of the case. While purporting to represent consumers, the AGO's theories and recommended disallowances are inconsistent with those of the Public Staff, tasked with representing the same constituency.

Witness Wittliff admitted that he did not identify any specific costs that could have been lower or should be disallowed. Id. at pp. 287-89. However, witness Wittliff continued to pose the theory that the Company "caused" CAMA, and while he cannot point to imprudent action on the part of DEC in undertaking to comply with CAMA, the fact that the Company "caused" the statute to be enacted affects its ability to recover its CAMA-related costs. Tr. Vol. 11, pp. 239, 248-50, 272. CUCA witness O'Donnell agrees. Tr. Vol. 18, pp. 59-60 (Company caused CAMA and therefore should not recover any CAMA cost).

In these witnesses' view, CAMA sets a more aggressive coal ash basin closure schedule for certain of the Company's basins than would have been set under the CCR Rule alone, and the more aggressive schedule leads, again in their view, to higher costs. Witness Wittliff testified that he "[didn't] know quantitatively, because [he] didn't do that kind of analysis," in regard to what costs the Company would have eventually been

[61] Sierra Club witness Quarles asserted that continued storage of coal ash at Allen and Marshall poses significant environmental risks, and concluded that closure in place at these basins would allow continued contamination of downgradient groundwater and violate the technical standards of the CCR Rule, and that removal of coal ash from DEC's ash basins would reduce the concentrations and extent of this contamination. Tr. Vol. 6, pp. 17-118; 119-27. Witness Quarles made no effort to quantify the economic impact of his recommendation, which would increase cost to customers. The Commission is persuaded by the evidence presented by witness Kerin and witness Moore that the closure plans for the Allen and Marshall Plants are appropriate. DEQ will be responsible for determining which closure plans are appropriate for Allen and Marshall. The Commission determines that the associated expense for Allen and Marshall is reasonable and prudent.

required to undertake by the CCR Rule and CAMA, despite any exceedances, violations, criminal prosecutions, and civil and administrative lawsuits. Tr. Vol. 11, pp. 282-83.[62] Accordingly, the Commission determines that witness Wittliff's opinion cannot legitimately support disallowances, because it fails with respect to the prudence review framework the Commission established in the 1988 DEP Rate Case: (1) it fails to identify specific and discrete instances of imprudence; (2) it fails to demonstrate the existence of prudent alternatives; and (3) most importantly, it fails to quantify the effects by calculating imprudently incurred costs.

Witness O'Donnell proposes a 75% disallowance, but he does so predicated not on a calculation of "imprudently incurred costs" as required by the Commission's framework, but rather based on what he terms a "financial analysis" through comparison of the size of the ARO established by the Company to capture coal ash basin closure expense associated with CCR Rule and CAMA compliance with the AROs established by other utilities to capture their coal ash basin closure expense. This "calculation" is unpersuasive, however, as demonstrated by witness Kerin, (see Tr. Vol. 24, pp. 124-28), and as the Commission determined in the DEP case. See 2018 DEP Rate Order, p. 196. In particular, the analysis lacks any attempt by witness O'Donnell to account for the differences in which different utilities may have valued their closure cost estimates, or the differences in the timing of their estimates. As the Commission held in the 1988 DEP Rate Order, industry comparisons, even if relevant, are "of little value in determining specific acts of imprudence." 1988 DEP Rate Order, p. 56. The Commission agreed with the Company's witness that "[t]he flaw in industry comparisons … is that there are unique conditions on every nuclear project so that no projects are exactly comparable" (<u>id.</u>), and the same applies to AROs established by different utilities to capture their specific coal ash basin closure costs. Witness Kerin indicates, and the Commission agrees, that this renders witness O'Donnell's "analysis" without significant probative value – it is not a true apples-to-apples comparison of the utilities' AROs.

A more fundamental reason demonstrates why the Commission determines it should not accept the opinions of witnesses Wittliff and O'Donnell – the notion that the Company was the direct cause of CAMA is of limited legal basis. Witness O'Donnell presents no evidence of such direct causation, and witness Wittliff appears to base his opinion on a draft preamble to the Senate bill (Tr. Vol. 11, pp. 240, 248-50), notwithstanding the fact that this preamble is not present in the final ratified bill.[63] Moreover, in North Carolina, legislative intent is ascertained by the plain words of the statute. <u>Rhyne v. K-Mart Corp.</u>, 149 N.C. App. 672, 562 S.E.2d 82 (2002). "Legislative history" of the type seemingly relied upon by witness Wittliff is legally impermissive. In <u>State v. Evans</u>, 145 N.C. App. 324, 550 S.E.2d 853 (2001), the Court stated:

[62] The AGO complains that the Commission imposes an inappropriate burden upon it to offer evidence to quantify the disallowances it advocates. The AGO cannot legitimately assert that the burden is unfair when it has failed to undertake the task of attempting to elicit that evidence. The AGO has undertaken substantial discovery of DEC in this case. Based on the omissions in its presentation, the AGO apparently failed to "close the loop" in seeking to elicit evidence on what it would have cost to take the remediation steps it alleges DEC should have taken prior to 2015.

[63] <u>See</u> N.C. Gen. Stat. § 130A-309.200, <u>et seq</u>.

> While the cardinal principle of statutory construction is that the words of the statute must be given the meaning which will carry out the intent of the Legislature . . . . [t]estimony, even by members of the Legislature which adopted the statute, as to its purpose and the construction intended to be given by the Legislature to its terms, is not competent evidence upon which the court can make its determination as to the meaning of the statutory provision.
>
> Thus, "[e]ven the commentaries printed with the North Carolina General Statutes, which were not enacted into law by the General Assembly, are not treated as binding authority by this Court." Accordingly, press releases and commission recommendations offered by defendant as evidence of the punitive purpose behind [the statute] are in no manner binding authority on this Court.

145 N.C. App. at 329-30, 550 S.E.2d at 857 (citations omitted). Accord. Elec. Supply Co. of Durham v. Swain Elec. Co., 328 N.C. 651, 657, 403 S.E.2d 291, 295 (1991); Styres v. Phillips, 277 N.C. 460, 472, 178 S.E.2d 583, 590 (1971) ("The intention of the legislature cannot be shown by the testimony of a member; it must be drawn from the construction of its acts.").[64]

Even if the actions or inactions of DEC or one of its sister companies was a direct cause of CAMA as these witnesses allege, such direct causation alone is not sufficient legal basis for disallowing otherwise recoverable costs. If the North Carolina General Assembly had intended to give the Commission the authority to deny otherwise recoverable environmental compliance costs due to some punitive theory of causation, it could have said so – and it did not. The legislature does not operate in a vacuum. Rather, it operates within the context of N.C. Gen. Stat. § 62-133, in which prudently incurred costs are recoverable. Had it intended to disavow the routine cost recovery standard, it can be expected that the legislature would have had to do so explicitly. Accordingly, witnesses Wittliff and O'Donnell theories of punitive causation do not comport with the controlling law of this state.

3. The Public Staff's "Equitable Sharing" Concept

In this case, as in the 2018 DEP Rate Case, the Public Staff advocates an "equitable sharing" of coal ash basin closure costs. The Public Staff's equitable sharing

[64] In Styres v. Phillips, the Supreme Court also stated that "the rule is that ordinarily the intent of the legislature is indicated by its actions, and not by its failure to act." Styres, 277 N.C. at 472, 178 S.E.2d at 590. Accordingly, the suggestion through cross-examination questions by the AGO (see, e.g., Tr. Vol. 13, p. 22) that as CAMA does not contain an express provision mandating cost recovery of compliance costs, the General Assembly did not intend for the statute to allow such costs, is also without any basis. To the extent that any such evidence is competent, the most relevant evidence regarding the General Assembly's failure to act is the fact that on two separate occasions the General Assembly was presented with the opportunity to mandate non-recoverability of compliance costs, and on both occasions the provision so stating did not pass.

proposal is supported by witness Maness. Tr. Vol. 22, pp. 70-85. Witness Maness achieves the sharing in the same manner in which he implemented the Public Staff's 50-50 sharing proposal in the 2018 DEP Case. First, he removes the unamortized coal ash basin closure costs from rate base, thereby, through that step, eliminating any return on that unamortized balance. Id. at 72. The second step is to choose an amortization period that will result in the desired level of "sharing." Id. The sharing level that the Public Staff and witness Maness deem "equitable" is 51% to the Company and 49% to customers. Id. at 84. Mathematically that results in a 27-year amortization period (id.), although, when adjusted for the rate of return to which the Company and the Public Staff agreed, subject to the Commission's approval, was appropriate in this case, the amortization period is reduced to 25 years. Id. at 153. Even under the 25-year amortization period, however, the sharing level remains 51% to the Company and 49% to customers. Id. at 162.

The Commission chose not to accept the "equitable sharing" concept in the 2018 DEP Case, and does so again, on the same basis.

First, the concept is standard-less, and, therefore, from the Commission's view arbitrary for purposes of disallowing identifiable costs – there is no rationale that supports a substantially large 51% disallowance. The Public Staff chose a desirable equitable sharing ratio, then backed into the mechanism to achieve that level of disallowance, leaving the allocation subject to an arbitrary and capricious attack, particularly as it provides no explanation as to why the "equitable" split for DEP in the 2018 DEP Case was in its view 50-50, while the "equitable" split in this case is 51-49. As the Commission held in the 2018 DEP Case, the "Public Staff provides insufficient justification for the 50/50 [split] as opposed to 60/40 or 80/20 …." 2018 DEP Rate Order, p. 189.

Black's Law Dictionary defines an "arbitrary and capricious" decision as one which, inter alia, is "without determining principle." See Tate Terrace Realty Investors, Inc. v. Currituck Cty., 127 N.C. App. 212, 222-23, 488 S.E.2d 845, 851 (1997). The Commission can discern no "determining principle" in the Public Staff's "equitable sharing" proposal. As such, were the Commission to adopt it, the Commission's action would be subject to an arbitrary and capricious attack and likely subject itself to reversal. An illustrative case is Sanchez v. Town of Beaufort, 211 N.C. App. 574, 710 S.E.2d 350 disc. review denied, 365 N.C. 349, 718 S.E.2d 152 (2011), in which the Court held that it was arbitrary and capricious for a municipal body to "cherry pick" a standard without providing any basis of any particular determining principle. Sanchez, 211 N.C. App. at 580, 710 S.E.2d at 354. In this case, the Beaufort Historic Preservation Commission (BHPC) attempted to limit the construction of petitioner's home to 24 feet in height "without the use of any determining principle from the BHPC guidelines." Id. at 582, 710 S.E.2d at 355. Rather, the BHPC members based the standard "on their own personal preferences," with each member providing a manner of re-working the project's construction to comply with a 24-foot height maximum, but none providing a reason as to why 24 feet when the height "could be a different number …." Id. at 581 (emphasis in original). Thus, while the BHPC members could provide a way to arrive at the height maximum, they could not provide a "why" for that particular height maximum. Failure to provide a determining principle for the height maximum itself rendered the BHPC's decision arbitrary and capricious. Id. at 582.

Ultimately, the Public Staff, through witness Maness, indicates that "what is and what is not allowed in rate base is within the legal discretion of the Commission to decide." Tr. Vol. 22, p. 73. The Public Staff overstates the Commission's discretion, and to the extent the Commission possesses such discretion, the Commission chooses not to exercise it in the manner the Public Staff advocates. To understand exactly how, it is necessary first to examine the Public Staff's purported rationales for its sharing proposal. There are two: first, the Company's alleged past failures, as detailed in the testimony of Public Staff witness Junis, to prevent environmental contamination from its coal ash basins, and, second, an asserted "history of approval of sharing of extremely large costs that do not result in any new generation of electricity for customers." Id. at 71-72.

As to the first asserted predicate, the Company disputes such "failures," as set out in the testimony of Company witness Kerin. The Commission credits Kerin's testimony, as detailed below, but whether or not the Company were guilty of some sort of violation is insufficient to justify the Public Staff's 51/49 sharing proposal. Witness Maness admitted that these alleged acts or failures to act are related to past operations. Tr. Vol. 22, p. 80. No persuasive evidence exists that any of these actions or inactions caused discrete expenditures by the Company to comply with its CCR Rule and CAMA obligations, which are the costs that the Company seeks to recover. Past actions, even if imprudent in this context must result in quantifiable costs, which the Public Staff has not shown. Therefore, identification of an imprudent action or inaction is not by itself sufficient; rather, there must be a demonstration of the economic impact. 1988 DEP Rate Order, p. 15. The Public Staff has made no such demonstration in this case, and no such demonstration with respect to the Public Staff's 51/49 sharing arrangement.

Apart from his specific recommendation regarding disallowance of groundwater remediation expense (discussed below), witness Junis' testimony does not link the past actions of the Company to the costs it seeks to recover. As Company witness Wright indicates, to link alleged past "violations" to current compliance costs in the factual context of this case is to "put the Company in an untenable situation." Tr. Vol. 13, p. 39.

Past violations may well be imprudent, but with respect to the "question of responding to new regulations and new standards, that is a totally separate question." Id. The Commission agrees with this distinction. In keeping with its decision in the 1988 DEP Rate Order, this aspect of which was affirmed by the North Carolina Supreme Court, to permit disallowance there must an actual expenditure shown to be imprudently incurred.

The Public Staff's position, simply stated, is that it does not matter if the Company's actions in incurring the CCR Rule and CAMA compliance costs were prudent – the Public Staff's equitable sharing proposal would still apply. As witness Maness testified, "[E]ven if 'prudent'" (Tr. Vol. 22, p. 126), the Public Staff would still find it "appropriate to have the shareholders of those companies bear a greater share of the cleanup costs under an equitable sharing approach." Id. Accordingly, the predominant rationale for the Public

Staff's proposal is witness Maness' second predicate: the proposition that the Commission has a "history of approval of sharing of extremely large costs that do not result in any new generation of electricity for customers." Id. at 72.

Witness Maness overstates his position – as witness Wright notes, there is "no provision of Chapter 62 requiring different treatment for 'extremely large costs'" (Tr. Vol. 12, pp. 156-21–156-22), and, witness Wright detailed any number of "extremely large cost" items not associated with new generation for which cost recovery is routinely allowed. Id. The Commission determines that this is another example of the arbitrariness inherent in the Public Staff's sharing proposal.

It appears that witness Maness' rationale for the sharing proposal is grounded in the Public Staff's view of the discretion available to the Commission. He states first that pursuant to N.C. Gen. Stat. § 62-133(b)(1), and with the exception of construction work in progress under certain circumstances, "the only costs that the Commission is required to include in rate base are … 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 ….'" Tr. Vol. 22, p. 73. He indicates that he is advised by counsel that "beyond these requirements what is and what is not in rate base is fully within the Commission's discretion to decide, as long as the rates set thereby are fair and reasonable to both the utility and the consumers." Id.

DEC and the Public Staff stridently debate whether the 2015-2017 CCR remediation costs if found used and useful and otherwise meet the test for amortization with a return on the unamortized balance "must" or "may" be approved. The Public Staff argues that approval of a return is discretionary. The Commission determines it unnecessary to determine whether the costs must receive a return on the unamortized balance. In its discretion, as expressly authorized by N.C. Gen. Stat. § 62-133(d), with the exception addressed below, it approves a return.

DEC argues that deferred 2015-2017 CCR remediation costs accounted for in an ARO as authorized by the Commission in its 2018 order should be amortized over five years and should earn a return on the unamortized balance. The Public Staff argues that these ARO costs should be amortized over 25 years with no return based primarily on an equitable sharing theory. In support of these parties' contrasting positions and in order to challenge the merits of their opposition, the parties laboriously debate issues of used and useful, "entitled" versus "eligible" for earning a return, plant in service versus working capital, capital costs versus expenses, etc. The parties arduously debate the applicability to this issue of cases addressing an abandoned sewage treatment plant, costs of discontinued nuclear projects, and manufactured natural gas remediation costs.

No witness argues that the Commission lacks the discretion to follow the precedent it established in the two previous cases, DNCP and DEP, where it addressed the issue of amortizing deferred ARO CCR remediation costs over five years and a return on the unamortized balance. No witness argues that the law forbids the Commission to authorize a return on the unamortized balance. The Commission chooses to exercise its discretion and authority under N.C. Gen. Stat. § 62-133(d) and follow its precedent here - amortize the ARO costs over five years and authorize a return on the unamortized balance. The Commission will address the lengthy arguments and debate, but determines that by and large the arguments are not particularly germane or dispositive to the Commission's decisions. The Commission will not accept the Public Staff equitable sharing argument primarily because the Commission determines in its discretion that amortization of the deferred ARO costs over 25 years is inequitable and finds inadequate support for a 50-50 or 51-49 sharing versus some other ratio. The justification for disallowance of 50% of the ARO costs is not persuasive. The Commission concludes that the Public Staff relies on the equitable sharing principle because it, like other Intervenors, has been unable to quantify a disallowance on the basis of the alleged DEC acts and omissions prior to 2015 providing the predicate for the requested disallowance. Instead, the Commission relies upon some of the evidence offered to support the equitable sharing theory to impose a management penalty as discussed below.

While arguments by the parties through analogy to cases on other issues provide some helpful context, the issue of amortization of deferred CCR remediation costs required to comply with EPA CCR requirements and CAMA is sui generis and distinguishable. These expenditures, as FERC and GAAP refer to them, are "costs" or an "asset" of remediation. They have been deemed by the Commission without objection as extraordinary, as not being recovered through current rates and have for those reasons been deferred. As such, they are investor-supplied funds, not ratepayer-supplied funds and under principles of equity, law and fairness are eligible for a return. Otherwise the investor supplying these funds is deprived of the time value of money and is inadequately compensated resulting in an increased risk and ultimately increasing the Company's cost of capital. The Commission in its discretion hereby authorizes a return, but discounts it as discussed below.

The nuclear discontinued plant costs, to the extent relevant to the issues in this case, are primarily so with respect to the Public Staff argument in support of equitable sharing. The Commission determines on balance that the support for equitable sharing the Public Staff argues these cases provide is unpersuasive. This is not to say that the Commission is of the opinion it could not approve an equitable sharing remedy in a given case outside the context of a nuclear plant discontinuance case, but this is not a nuclear plant discontinuance case and not one the Commission chooses to rely upon to authorize equitable sharing. The costs the electric utilities incurred at issue in those cases were for nuclear plants, that had they been placed on line and generated electricity would have been added to rate base as used and useful plant in service. Some of the costs were for plants actually placed on line but sized to serve more units than the units actually generating electricity and therefore constituted excess capacity or plant not "useful." The costs had never been placed in rate base as plant in service prior to the general rate cases at issue, and to the extent they were costs in abandoned nuclear facilities, they were facilities never used to generate electricity. Those are not the facts at issue here. None of the nuclear plant discontinuance cases either before the Commission or the courts on appeal held that to the extent a portion of the costs could be recovered, they were ineligible for any return on the undepreciated balance, just that the costs should not be added to rate base. In fact, in the past, the Commission has approved a return. Order dated September 24, 1982, Docket No. E-2, Sub 444. (Commission authorized recovery of costs associated with cancelled Harris Units 3 and 4 over a ten-year period with inclusion of the interest arising from the debt financing portion of the unamortized balance.)

The costs of the sewage treatment plant at issue in Carolina Water were classified as abandoned plant. The plant long having been in service had been taken out of service, and it would never be used again because service would be provided by contract with a governmental agency. A portion of the original costs to build the plant had not been recovered through depreciation at the time of abandonment. That is not the factual situation in this case. Here there is a deferral of ARO CCR remediation costs. New costs were incurred in 2015-2016 in addition to creation or maintenance of the impoundment in prior years.[65]

The MFG case is somewhat analogous, but does not address billions of dollars of CCR remediation costs incurred to comply with EPA and CAMA requirements accounted for in a deferred Commission approved ARO. The Commission is unable to discern whether the natural gas utility was required to construct lined landfills in which to place contaminated materials or construct caps over any existing repositories. The MFG case was a Commission decision, one the Commission may follow or not as it determines appropriate. For reasons fully explained herein, it determines not to follow it.

As to Public Staff arguments that the ARO costs or assets were all "capitalized expenses," the Commission, were it necessary to resolve this issue, would disagree. For example, a significant portion of the costs compiled in the asset retirement obligation has been or will be spent on creation of lined landfills with synthetic liners or impermeable caps over existing impoundments. These structures are examples of long-lived assets and are capital in nature- not expenses. Another significant portion, had they not been accounted for in an ARO and deferred, would have been operating or other expenses.[66] However, while expenditure of costs outside of the ARO context that are deferred may

[65] The issues of earning on the abandoned wastewater treatment plant was not the major issue before the Court in the Carolina Water case. The ultimate issue before the Commission was whether the unrecovered costs of the sewage treatment plant should be treated as plant held for future use of abandoned plant. Discussion of this issue consisted of less than two pages in a 126-page order. The monetary consequences amounted to a few thousand dollars per year. Docket No. W-354, Sub 111, Order dated July 31, 1992, pp. 56-58. The facts at issue in the case are unlikely to be repeated. Under the Uniform System of Accounts, the costs of individual components, in many instances, are combined into classes for calculating depreciation rates and net salvage value. Within these classes many individual components retire before or after the end of their projected useful lives. These retirements affect the recalculated depreciation rates, but the individual components are not classified as abandoned plant. See Tr. Vol. 2, Doss Ex. 3. Hahne & Aliff, Accounting for Public Utilities § 6.04 pp. 6-8, 6-10, § 6.05[3] pp. 6-12.

[66] 2016 is the twelve month test year in this case. To the extent the Commission had not authorized deferral of the ARO in 2016, the non-capital portion of the CCR remediation costs to the extent reasonable and prudent would be recoverable dollar-for-dollar in the revenue requirement. The portion spent on capital projects to the extent comprising completed projects would be added to rate base and eligible to earn a return.

include what otherwise would be classified as "expenses," e.g., operating costs, when they are capitalized and by order of the Commission are deferred, they lose for ratemaking purposes the attributes of test year recurring "expenses" deemed recoverable through the rates then in effect that do not qualify for a return. To the extent they qualify for recovery “of” (versus recovery “on”) test year expenses in a general rate case through N.C. Gen. Stat. § 62-133(b)(3), they are recoverable as "actual investment currently consumed through reasonable actual depreciation" (amortization) rather than traditional test year, recurring "reasonable operating expenses." The Commission determines that while sui generis these ARO costs in totality are more closely related to deferred production plant costs than deferred storm damage costs, for example.

In Footnote 2 on page 5 of the Public Staff brief, the Public Staff contends:

> [2] Thornburg I provides that the Commission has discretionary authority to award or deny a return on the unamortized balance. A subsequent decision of the North Carolina Supreme Court indicates such deferred operating expenses are not eligible for a return on the unamortized balance: "Costs for abandoned property may be recovered as operating expenses through amortization, but a return on the investment may not be recovered by including the unamortized portion of the property in rate base." State ex rel. Utils. Comm'n v. Carolina Water Serv., 335 N.C. 493, 508 (1994) (Carolina Water Service). This decision did not expressly overrule Thornburg I, but nonetheless suggests that a return on unamortized balance of a regulatory asset is not a discretionary matter for the Commission; instead it may be prohibited by law.[67] For purposes of the present Post-Hearing Brief, the Public Staff position is that under either the Thornburg I holding or the Carolina Water Service holding, there is no DEC entitlement to a return on the unamortized balance of its deferred coal ash costs.

The Commission finds the contention inaccurate that the cited cases deny the Commission discretion to authorize a return on a deferred CCR remediation ARO. The nuclear plant discontinuance costs at issue in Thornburg I were not "deferred operating expenses" like deferred CCR ARO costs, and the abandoned water treatment plant costs

[67] While the Public Staff suggests that authorizing a return on the unamortized balance might not be discretionary, this suggestion is belied by the Public Staff’s alternative remedy for disallowing CCR remediation costs set forth on page 422 of its proposed order:

> Consequently, the Commission in the exercise of its judgment and discretion, determines that a management penalty in the approximate sum of $72.3 million is appropriate with respect to DEC CCR remediation expenses accounted for in the earlier established ARO with respect to costs incurred through the end of the test year as adjusted. . . . Had the Commission not imposed this penalty, the deferred coal ash costs would have been amortized over five years with a full authorized return on the unamortized balance. The penalty will be imposed by reducing the resulting annual amortization expense by approximately $14.46 million (from the return on the unamortized balance in the rate base portion) for each of the five years, resulting in an approximate $72.3 million management penalty.

at issue in Carolina Water likewise were not deferred "regulatory asset" costs comparable to either deferred nuclear plant discontinuance costs or deferred CCR ARO costs.[68] The Commission notes that it has authorized deferral of capital costs in utility plant (e.g., combined cycle natural gas fired electric generating plants) completed and placed in service prior to the test year or prior to the end of the test year of a general rate case to prevent loss of recovery of costs. The costs so deferred are not test year recurring operating expenses but deferred capital costs, added to rate base and eligible for a full return. A used and useful analysis is appropriate to determine recovery of these costs. Docket No. E-22, Sub 532 (Dec. 22, 2016) (2016 DNCP Rate Order)

The Public Staff also argues inaccurately and misleadingly that “it generally makes no regulatory sense to defer to a regulatory asset a cost that could be placed in rate base – deferral is used when necessary to prevent significant erosion of earnings, which is applicable to expenses but not to property that can be put in rate base; . . . .” In the Commission’s December 22, 2016 order in the most recent DNCP general rate case, Docket No. E-22, Sub 532, the Commission approved a stipulation between the Company and the Public Staff to defer the post-in-service costs of the Warren County CC and the Brunswick County CC. These plant-in-service electric production assets had been placed in service prior to the end of the general rate case test year, and the deferral postponed the date on which depreciation costs began and permitted return on the full costs of the assets. This deferral related to property, not expenses.

From the outset, the Public Staff has acknowledged and recognized that the ARO costs do not fit into traditional categories: "The Public Staff believed that the non-capital costs and depreciation expense related to compliance with state and federal requirements ... these very unique deferred expenses . . . the unusual circumstances of these costs . . . the unique nature of the costs and the complexity of the issues surrounding the determination of ultimate rate recovery." Tr. Vol. 18, pp. 300-01, Docket No. E-2, Sub 1142.

In the Commission's attempt to obtain a classification of the types of costs included in the ARO in the DEP case, witness Maness listed among others, site preparation, site infrastructure, construct a landfill, cap-in-place, capital expenditures related to equipment and facilities." Tr. Vol 19, p. 58. Under any analysis, these are not expenses but capital items. Had DEC not sought establishment of an ARO and deferral, it is incorrect that they would not have been added to plant in service and depreciated over their useful lives.

[68] While the regulatory accounting concepts of creation of a “regulatory asset/liability” and “deferral” include a wide spectrum of cost categories, this Commission views differently costs incurred before the test year of a general rate case (like extraordinary storm costs) and costs otherwise recognizable as test year costs or expenses but deferred for non-traditional future recovery such as nuclear plant discontinuance costs that are not added to rate base but are nonetheless amortized over future years. Costs in the former category are deferred to prevent loss of recovery. Costs in the latter category generally are deferred to limit, reduce or postpone recovery.

In Docket No. E-2, Sub 1142, witness Maness was asked why certain ARO capital costs were not appropriately classified as used and useful.

Q. Just to be clear, one of the things we are doing -- we showed it up on the screen here yesterday - we are putting liners under these coal ash pits, right?
A. Yes, sir.
Q. And that's - and we are putting caps or proposing to put caps over some coal ash basins?
A. Yes.
Q. Isn't that used and useful expenditure to keep the coal ash where it belongs?
A. Well, that raises a number of interesting questions, and I can't pretend to be able to answer them in detail. I have been searching for some answers in the accounting literature and haven't found anything direct yet."
Tr. Vol. 19, pp. 65-66.

Upon being questioned and when given the opportunity to support its position that the deferred ARO costs are "expenses," the Public Staff simply was unable to do so.

When witness Maness was asked whether classifying the ARO costs as used and useful made any difference to the outcome of the case, he responded, "I don't think it makes any difference in this case." Tr. Vol. 19, p. 66. The Commission agrees.

The Commission does agree with the Public Staff and others that even if the ARO deferral costs are found used and useful and that a 9.9% rate of return on rate base is appropriate, the Commission nevertheless has authority to disallow a portion of the return on the ARO costs due to mismanagement. This is what the Commission has required, and it is legally justified in doing so.

As expressed through witness Maness' testimony, the Public Staff looks to the Commission's Order Granting Partial Increase in Rates and Charges in Docket No. E-2, Sub 526 (Aug. 27, 1987) (1987 DEP Rate Order) and its affirmance by the Supreme Court in Thornburg I, 325 N.C. 463, 385 S.E.2d 451 (1989) as precedent for its equitable sharing concept. The Commission determines that Thornburg I provides less support for the equitable sharing the Public Staff advocates when viewed within the context of other cases addressing nuclear plant discontinuance costs. Greater context is found in Thornburg II, the 1988 DEP Rate Order and the Commission's Order Denying Motions for Reconsideration in the 1988 DEP Rate Case (Docket No. E-2, Sub 537) (1988 DEP Reconsideration Order), and the Supreme Court's reversal in part of those orders in Thornburg II, 325 N.C. 484, 385 S.E.2d 463 (1989).

The principal issue in the 1987 DEP Rate Case/Thornburg I was whether the Company could recover in rates any portion of the costs associated with the abandoned Units 2, 3, and 4 of the Shearon Harris nuclear plant. The Commission had previously decided that the Company could amortize the costs associated with these abandoned units over a ten-year period, but that "no ratemaking treatment should be allowed which would have the effect of allowing … [the Company] to earn a return on the unamortized balance." 1987 DEP Rate Order, p. 61. Over the objections of the AGO, the Commission decided to continue to follow that process in the 1987 case – it allowed amortization of abandonment costs over a ten-year period, what the court classified as an operating expense[69] for the purposes of rate recovery under N.C. Gen. Stat. §§ 62-133(b)(3) and 62-133(c), but no return. The Supreme Court, in a passage extensively quoted in witness Maness' testimony (Tr. Vol. 22, pp. 75-76), affirmed the Commission's decision, holding that N.C. Gen. Stat. §§ 62-133(b)(3) and 62-133(c) were elastic enough to include non-recurring abandonment costs as utility test year "expense," and that N.C. Gen. Stat. § 62-133(d), which allows the Commission to factor in "all other material facts of record that will enable it to determine what are just and reasonable rates," also provided support for the Commission's decision. The Court further held that as a matter of policy a return of, but not a return on, the abandonment costs was appropriate. Thornburg I, 325 N.C. at 476-81, 385 S.E.2d at 458-61. The Commission had not authorized a return on the costs at issue. The contested issue was recovery of not recovery on the nuclear investment costs.

In Thornburg I, the Court held specifically that the Commission's recovery of but no return on decision was "within the Commission's discretion" and would not be disturbed. Id. at 481. That decision effected a "sharing" between the Company's shareholders, on the one hand, and its customers, on the other – shareholders received a return of the costs, but no return on the costs. It is based upon this holding that the Public Staff, through witness Maness' testimony, contends that "reasonable rates can include a sharing between ratepayers and investors with regard to plant cancellation costs" (Tr. Vol. 22, p. 75), and that the Commission possesses discretion to implement this sharing.

There are, however, distinctions between the 1987 DEP Rate Case/Thornburg I and the present case. First this case does not involve "abandoned plant" or cancellation costs. Rather, it involves an asset retirement obligation and whether or not the unamortized balance is eligible for a return. As such, the authority that the Public Staff relies upon to support its "equitable sharing" concept is not directly on point. This is illustrated by examining the prior orders of this Commission and the subsequent Thornburg case: the 1988 DEP Rate Order, the 1988 DEP Reconsideration Order, and Thornburg II.

In the 1988 DEP Rate Case, the principal issue for decision was the reasonableness and prudence of the costs of constructing and placing into service Unit 1 of the Shearon Harris nuclear plant. The Commission found that for the most part, Harris

[69] While the Court's use of the term "operating expense" is technically correct as referenced in the statute, the more precise term should have been "actual investment currently consumed through reasonable actual depreciation" (amortization) in N.C. Gen. Stat. § 62-133(b)(3). The costs at issue are not recurring operating and maintenance or other "expenses" expended in the test year. They are ever decreasing costs allowing a "return of," but not a "return on" the nuclear plant costs. See Tr. Vol. 9, pp. 115-131; Vol. 10, pp. 14-28.

Unit 1 costs were reasonable and prudent, and that determination in the 1988 DEP Rate Order was upheld by the Supreme Court. Thornburg II, 325 N.C. at 488-89, 385 S.E.2d at 465-66 (finding "no error" in that part of the Commission's Order). However, a part – $570 million-worth – of the costs the Commission considered were incurred in connection with facilities to be shared with Units 2, 3, and 4, units that the Company had ceased to construct to completion. The Commission found that while these $570 million in costs were prudently incurred, they should be shared between the Company's customers and its shareholders. The Commission found that approximately $180 million of those costs were properly classified as "abandonment" costs and should be borne by shareholders. 1988 DEP Rate Order, pp. 112-14. The remaining $390 million were left in rate base.

Responding to the Public Staff's request that the Commission reconsider this decision and remove the entire $570 million from rate base on the grounds that all of it related to abandoned plant, the Commission reaffirmed its decision in the 1988 DEP Reconsideration Order and provided additional explanation for its ruling. It stated that the Public Staff's request that the full $570 million for the common facilities be treated as abandonment costs was based upon a "misunderstanding" of the 1988 DEP Rate Order and the Commission's objective in splitting this $570 million item into $390 million of rate base and $180 million of cancellation costs. 1988 DEP Reconsideration Order, pp. 2-3. The Commission did not (it says in the 1988 DEP Reconsideration Order) intend to treat the "excess common facilities" as abandoned plant; rather, it effected an "equitable sharing" (emphasis added) of the $570 million between customers and shareholders. The Commission reiterated that the Company's choice of the cluster design – which engendered the shared facilities – was reasonable and prudent, and that except as specifically indicated in the 1988 DEP Rate Order, the costs of the Shearon Harris plant were "reasonable and prudently incurred." Thus, the Commission found, the $570 million at issue was also reasonably and prudently incurred.

Nevertheless, the Commission held, (id. at 4-5), that it was appropriate to share the $570 million at issue, and it indicated that it came up with the allocation (essentially one-third to cancellation costs and two-thirds to rate base) on its own and adopted it "for reasons of fairness and equity." The Commission held that it continued "to believe that a reasonable and equitable apportionment of the burden and risks associated with … [the Company's] prudent investment in common facilities is appropriate." It stated further that its assignment of $180 million as the value of the Company's prudent investment in common facilities to be treated as cancellation costs for ratemaking purposes was an appropriate exercise of its "regulatory discretion."

The Supreme Court disagreed. It held that the Commission did not have the discretionary power to effectuate its "equitable sharing" decision. Rather, the facilities were either "used and useful," and therefore in rate base, or they were not. The Court looked to the Commission's finding that the facilities in question were "excess common facilities," and held that "excess" facilities were not "used and useful" as a matter of law. Thornburg II, 325 N.C. at 495. Accordingly, looking to the broader spectrum of Commission and Supreme Court precedent, the Commission determines not to approve the Public Staff's "equitable sharing" concept through reliance on the nuclear plant discontinuance cost cases.

4. ARO Accounting and "Used and Useful"

In the 2018 DEP Rate Case, the Public Staff argued that the Commission had the discretion to implement the "equitable sharing" concept based upon the Public Staff's interpretation of prior Commission orders and decisions of the North Carolina Supreme Court that permit equitable sharing in the case of abandoned nuclear plants or long out-of-use manufactured gas plants. As noted above and in the 2018 DEP Rate Order, the Commission determines not to approve the Public Staff equitable sharing recommendation. In the 2018 DEP Case, the Commission held to the contrary that

> Costs placed in an ARO account are eligible for deferral and amortization and for earning on the unamortized balance. As such, even if the remediation costs are ARO expenditures, they are eligible for ratemaking treatment as though they are used and useful assets.

2018 DEP Rate Order, p. 196. In this case, Public Staff disputes this as a matter of accounting, and concludes on the basis of its interpretation of the accounting standards that the Company's coal ash basin closure expenditures cannot be classified as "used and useful." As it did in the 2018 DEP order, the Commission determines that it can authorize a return on the unamortized ARO costs.

The Public Staff's position is advanced by witness Maness. Starting from the premise that the Company "chose" to account for its coal ash basin closure costs through ARO accounting, witness Maness makes three basic points. First, he indicates that the Company's deferred coal ash basin closure costs placed in the ARO are more properly categorized as deferred expenses, in that the ARO is "a regulatory accounting and ratemaking method that does not explicitly account for any coal ash compliance costs, either in the past or in the future, as the capitalized costs of property, but instead accounts for them as ongoing expenses …." Tr. Vol. 22, p. 79. Second, he states that the fact that the Company classifies these costs as "working capital" is irrelevant, and merely a matter of convenience. Id. at 81. Third, he asserts that these costs cannot possibly be classified as "used and useful," because (in his view) that term applies only to utility plant, not expenses. Id. at 77. The Commission disagrees, but as the Public Staff agrees that the Commission possesses the discretion to approve a return on the unamortized balance of the deferred CCR remediation ARO costs, the Commission finds the debate for purposes of this case to be for the most part an academic one.

First, the Commission disagrees that the Company "chose" ARO accounting. The Commission has already so held in the 2018 DEP Case: "Once it became clear that the new laws and regulations governing coal ash would require closure of the Company's existing coal ash basins, GAAP required that an ARO be established, and the Company had no choice in the matter." 2018 DEP Rate Order, p. 194.[70] Further, as Company witness Doss testified, in addition to GAAP requirements "the Company was also required to (and did) adhere to and apply the accounting guidance under … [the] Federal Energy Regulatory Commission ('FERC') Code of Federal Regulations ('CFR'), as well as Orders of this Commission." Tr. Vol. 12, p. 62. The Company's ARO accounting complies with the authoritative statements of GAAP, FERC, and this Commission.

Witness Doss provided an extended explanation of the GAAP, FERC, and deferral directives that govern the manner in which the Company established the ARO and has accounted for coal ash basin closure costs in the ARO. The Commission credits his explanation and testimony, which are un-contradicted.

a. GAAP

The CCR Rule and CAMA were new laws that compelled basin closure under GAAP.[71] As Company witness Doss indicated, "The closure obligation triggered ARO accounting requirements." Tr. Vol. 12, p. 63. He elaborated:

> Statement of Financial Accounting Standard ("SFAS") No. 143 (now codified as ASC 410) was effective for and implemented by the Company in 2003 for financial reporting purposes. This guidance requires recognition of liabilities for the expected cost of retiring tangible long-lived assets for which a legal retirement obligation exists. GAAP (in ASC 410-20-20) refers to these costs as an "Asset Retirement Obligation" or an ARO, and defines a "legal obligation" as an "obligation that a party is required to settle as a result of an existing *or* enacted law …." (Emphasis added). Each of CAMA and the CCR Rule qualify as an "enacted law" under this guidance.

Id. As he explained further (id. at 64-65), GAAP requires ARO accounting for the closure costs under ASC 410-20-15. Specifically, Subtopic 15-2 indicates that the guidance applies to the following transactions and activities:

a) Legal obligations associated with the retirement of a tangible long-lived asset that result from the acquisition, construction, or development and (or) the normal operation of a long-lived asset, including any legal obligations that require disposal of a replaced part that is a component of a tangible long-lived asset.
b) An environmental remediation liability that results from the normal operation of a long-lived asset and that is associated with the retirement of that asset. The fact that partial settlement of an obligation is required or performed before full

[70] As the Public Staff and the Commission have noted previously, "Statements of the FASB are officially recognized by the Securities and Exchange Commission (SEC) as authoritative with regard to GAAP in the United States, and the requirements included in those Statements are essentially mandatory for any publicly traded entity." See Order Granting in Part and Denying in Part Request for Deferral Accounting, Docket E-7, Sub 723 (April 4, 2003), pp. 11-12.

[71] The applicable GAAP guidance is contained in Doss Rebuttal Ex. 1.

retirement of an asset does not remove that obligation from the scope of this Subtopic. If environmental contamination is incurred in the normal operation of a long-lived asset and is associated with the retirement of that asset, then this Subtopic will apply (and Subtopic 410-30 will not apply) if the entity is legally obligated to treat the contamination.

c) A conditional obligation to perform a retirement activity. Uncertainty about the timing of settlement of the asset retirement obligation does not remove that obligation from the scope of this Subtopic but will affect the measurement of a liability for that obligation (see paragraph 410-20-25-10).

Here, the coal ash basins being retired are tangible long-lived assets, and so Subtopic 15-2(a) applies. In addition, to the extent that retirement involves any environmental remediation, that remediation is the result of the normal operation of the basins, which is the subject of Subtopic 15-2(b). As noted in Company witness Kerin's testimony, the use of ash impoundments as a storage location for coal ash and other CCR was in accordance with industry standards and then-applicable regulations. Finally, under Subtopic 15-2(c), the retirement requirements are a conditional obligation to perform a retirement activity as the nature, timing and extent of the closure depends on various determinations. In CAMA those determinations revolve around the legislative or the North Carolina Department of Environmental Quality assessed risk rankings. Under the CCR rule, those determinations revolve around the evaluation of certain criteria by specific deadlines.

Upon recognition that ARO accounting is required, GAAP further indicates that the entity "shall capitalize an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability." ASC 410-20-25-5; see also Tr. Vol. 12, p. 20.

The reference in ASC 410-20-15-2(b) to environmental compliance costs in connection with "normal operation" highlights an important distinction in this case with respect to the Company's coal ash basin closure costs. GAAP distinguishes between costs associated with "normal" and "costs associated with improper" operation. The Company has demonstrated that "normal" operation applies.

The distinction is detailed in witness Doss' testimony. Subtopic 410-20 of the ARO guidance applies to "normal operation" (see ASC 410-20-15-2(b); Doss Rebuttal Ex. 1, p. 2 of 28), and permits their inclusion in an ARO. Subtopic 410-30 applies to improper operation (see ASC 410-20-15-3(b); Doss Rebuttal Ex. 1, p. 2 of 28), and excludes them from an ARO. For example, as witness Doss testified, "Costs associated with the Company's Dan River spill … are covered by Subtopic 15-3(b), and, therefore, are not included in the coal ash basin closure ARO." Tr. Vol. 12, p. 66. This comports with the GAAP guidance itself, which notes that "a certain amount of spillage may be inherent in the normal operations of a fuel storage facility, but a catastrophic accident caused by noncompliance with an entity's safety procedures is not." See ASC 410-20-15-3(b); Doss Rebuttal Ex. 1, pp. 2-3 of 28. The guidance notes further that the spillage costs are properly within the ARO, while costs resulting from the catastrophic accident are excluded. Id.

GAAP guidance notes that "whether an obligation results from the normal operation of a long-lived asset may require judgment." See ASC 410-20-55-7; Doss Rebuttal Ex. 1, p. 11 of 28. Witness Doss acknowledged this. Tr. Vol. 12, p. 111. But it is not unbridled or arbitrary judgment. To the contrary, the exercise of judgment is carefully circumscribed through internal and external controls.

Witness Doss described these controls at length in his testimony. He noted that "DEC has implemented a Coal Ash ARO Charging Committee whose purpose is to evaluate costs to be incurred for determination as to whether they qualify for ARO accounting treatment … [and that decisions] of the Coal Ash ARO Charging Committee are summarized in a charging guidelines document." Id. at 66-67. These decisions are reviewed internally by the Company's "Coal Combustion Products (CCP) group to ensure that 1) all relevant facts were appropriately communicated by CCP and understood by the Committee, and 2) that the CCP group understands the decisions to properly categorize actual project costs." Id. at 67. Finally, any ARO-related cost classification is also reviewed by the Company's external auditor, Deloitte & Touche LLP, which in the course of its annual audit issues its opinions that the Company's financial statements are presented fairly in all material respects and in accordance with GAAP, and that the Company has effective internal control over financial reporting. Id. at 67-68.

The Commission determines that the evidence that the coal ash basin closure costs incurred by the Company, and for which it seeks recovery in this case, result from the "normal," non-catastrophic operation of the Company's coal ash basins is compelling. It is detailed above in connection with the Commission's discussion of the Company's prima facie case, and need not be repeated. The Company has demonstrated that its coal ash management practices, storage of CCR in unlined ash basins, complied with the then-applicable regulations and with industry practice. Seepage from unlined basins is therefore part of the "normal operation" of those basins.

b. FERC

Witness Doss also explained the FERC accounting guidance. He noted that the Company is regulated by FERC, and therefore required to use the FERC Uniform System of Accounts, which states, in relevant part:

> An asset retirement obligation represents a liability for the legal obligation associated with the retirement of a tangible long-lived asset that a company is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel. An asset retirement cost represents the amount capitalized when the liability is recognized for the long-lived asset that gives rise to the legal obligation. The amount recognized for the liability and an associated asset retirement cost shall be

> stated at the fair value of the asset retirement obligation in the period in which the obligation is incurred.

Tr. Vol. 12, p. 68. He noted further that the FERC Uniform System of Accounts General Instruction No. 25 requires that:

> a utility initially record a liability for an ARO in Account 230 — Asset Retirement Obligations, and charge the associated asset retirement costs to the electric utility plant that gave rise to the legal obligation in Account 101- Electric Plant in Service. The asset retirement cost is to be depreciated over the useful life of the related asset that gives rise to the obligation by recording a debit to Account 403.1- Depreciation Expense for Asset Retirement Costs and a credit to Account 108 Accumulated Provision for Depreciation of Electric Utility Plant. In periods subsequent to the initial recording of the ARO, the utility shall recognize the period-to-period changes of the ARO that result from the passage of time due to the accretion of the liability by recording a debit to Account 411.10 — Accretion Expense, and a credit to Account 230.

Id. at 68-69.

Commission's Deferral Order and Summary of Accounting Rules and Deferral

In 2003, after the Financial Accounting Standards Board required the implementation of the ARO accounting guidance, the Commission ruled in Docket No. E-7, Sub 723 "That the implementation of SFAS 143 [now codified as ASC 410] for financial reporting purposes and the deferrals allowed in this docket shall have no impact on the ultimate amount of costs recovered from the North Carolina retail ratepayers for nuclear decommissioning or other AROs, subject to future orders of the Commission." See Order Granting Motion for Reconsideration and Allowing Deferral of Costs, Docket E-7, Sub 723 (August 8, 2003), p. 12. As witness Doss explains,

> The cash outflows to settle the ARO are not recorded as an expense of DE Carolinas. The Company has already recognized depreciation expense through the life of the asset and accretion expense over the period of expected settlement of the ARO, and these costs were capitalized previously as part of the Asset Retirement Cost related to the ARO. See ASC 410-20-25-5. However, in the case of DE Carolinas and pursuant to the Commission's Order in Docket No. E-7, Sub 723, the depreciation and accretion expenses were deferred. The amount spent related to the coal ash basin closure ARO is effectively the portion of the deferred depreciation and accretion expense which has now been incurred as a cash outflow and which is "subject to the future orders of the Commission" as stated in the Order. Therefore, the Company's deferral request of costs incurred and the recovery request in this rate case are in accordance with the deferral Order the Commission issued in Docket No. E-7, Sub 723.

Tr. Vol. 12, p. 70.

While the accounting rules detailed herein are complex, in simplified terms, both GAAP and FERC accounting guidance require the recognition of a liability (the ARO) upon the requisite triggering event – the legal obligation to retire the Company's coal ash basins. Recognition of the liability carries with it recognition of a corresponding asset – the capitalized cost of settling the liability, which under both GAAP and FERC rules is considered part of the property, plant and equipment for the assets that must be retired. While under ordinary circumstances these recognition events would be reflected over time in the Company's income statements, because of the deferral order in Docket No. E-7, Sub 723, the income statement impacts are deferred into regulatory assets "pending further orders of the Commission." The Company in this case is seeking such a further order, so as to reflect in rates the outflow of cash that it has incurred – and that its investors have funded – as it proceeds to settle the asset retirement obligation created by the CCR Rule and CAMA.

c. The Savoy Letter

The Company's accounting of its coal ash costs has not occurred in a vacuum. Over 20 months before DEC filed its application to increase rates in this docket, it sent a letter to the Commission, copying the Public Staff, in which the Company detailed exactly how it was accounting for its coal ash basin closure costs. See Letter dated December 21, 2015 from Brian D. Savoy, the Company's SVP, Chief Accounting Officer, and Controller to Gail L. Mount, Chief Clerk (Savoy Letter), filed in Docket No. E-7, Sub 1110.[72] The Savoy Letter:

- Describes the GAAP and FERC accounting requirements regarding AROs;
- Describes the triggering events for the creation of the ARO, noting the promulgation of the CCR Rule and the passage of CAMA;
- Indicates that an ARO related to the closure of coal ash basins was recorded on the Company's balance sheet;
- Indicates further that a corresponding asset was recorded "as part of the associated coal plant in the property, plant and equipment (PP&E) accounts, or if associated with a retired coal plant, recorded in regulatory assets"; and
- Noted that "[c]onsistent with the requirements of the Commission's Order dated August 8, 2003 in Docket No. E-7, Sub 723 … all income statement impacts relating to the AROs ultimately reside in regulatory asset accounts."

Witnesses Fountain and McManeus were examined at length regarding the Savoy Letter at the evidentiary hearing. Tr. Vol. 9, pp. 117-24. That examination established, inter alia,

[72] This Docket was established on March 28, 2016 by order of the Commission, and the Savoy Letter placed therein, so as to acknowledge the Letter and allow other parties with interest to be made aware of it. See Order Acknowledging Receipt of Filing, Docket No. E-7, Sub 1110 (Mar. 28, 2016). The order recited that no filings were made in response to the letter as of the time the Docket was established, and indeed, no substantive filings were made thereafter until the Company filed its Petition for Accounting Order on December 30, 2016, formally seeking deferral of coal ash basin closure costs. The Sub 1110 Docket has been consolidated with this rate case docket.

that basin closure costs, whether they be denominated capital costs, O&M costs, general administration costs are nevertheless capitalized in connection with the establishment of the ARO; that such costs are extraordinary and not reflected in the Company's then-current rates; and, therefore, needed to be set aside and deferred so that the Company would not lose recovery of those costs "to the detriment of the stockholder." Id. at 123-24.

No party takes issue with the Company's accounting of coal ash basin closure costs in an ARO, as detailed in the Savoy Letter. Certainly, the Public Staff does not – witness Maness' testimony does not challenge the basis for or the propriety of the accounting treatment, he comes to a different conclusion regarding the effect of such treatment upon the Company's entitlement versus its eligibility to earn a return on the unamortized balance of those costs. As noted previously, Intervenors have a burden of production when challenging the Company's costs. This principle equally applies to the accounting for costs. The Commission determines that the Company has met this burden. The Public Staff challenge makes the issue ripe for the Commission to address the issue on the merits. The Company has met its burden of showing that the costs it seeks to recover are not only reasonably and prudently incurred, but also appropriately accounted for in ARO accounting, and the Commission agrees that based on its determinations on the merits that recovery is appropriate except as addressed below.

Several consequences flow from this determination. First, deferred costs are costs "that have been paid for by the … [utility] but have yet to be included for ratemaking purposes …." Lesser & Giacchino, p. 52. Through the Savoy Letter, the Company told the Commission and the Public Staff, and the Commission told all interested parties, exactly how the Company's coal ash basin closure costs were being accounted for, and explicitly indicated that the costs were being deferred pursuant to the Commission's orders in Docket No. E-7, Sub 723. Neither the Public Staff nor anyone else, including the AGO, raised any objection.

Nor did the Public Staff or the AGO raise any objection when the Company made its formal deferral request in 2016. Tr. Vol. 9, p. 126. The Public Staff however asserts that deferral for regulatory accounting purposes is appropriate, given the magnitude of the costs and their potential impact upon the authorized rate of return. The nature of the deferral is such that all costs, no matter how classified, related to the Company's coal ash basin closure obligations are accounted for in the ARO. Id. p. 125. The ARO was established for this purpose, as the Savoy Letter makes clear. As such, the Commission determines that even were it necessary to resolve this issue, witness Maness' classification of these costs as "deferred expenses" is not persuasive, not supported by authority and not determinative, given the nature of deferral.

It is also incorrect as a matter of accounting. As witness Doss testified, "The Company has accounted for these costs as required under GAAP and FERC Uniform System of Accounts." Tr. Vol. 12, p. 71. Under GAAP, the costs (no matter what their classification) are capitalized pursuant to ASC 410-20-25-5. Id. at 70. Under FERC accounting, they are capitalized as well. Id. at 68-69. Accordingly, when properly accounted for in an ARO, the specific classification of costs is not determinative, because under GAAP and FERC guidance ARO costs are capitalized. The nomenclature relied upon in GAAP and FERC is costs, assets, and liabilities, not "expenses."

Likewise, witness Maness' criticism that these costs are placed in "working capital" is also not determinative. Witness Maness, without support and solely as a matter of opinion, states that the Company's inclusion of the deferred balance of coal ash basin closure costs in the "working capital" portion of rate base is merely a matter of convenience. Tr. Vol. 22, p. 81. He does not state that their inclusion in working capital is incorrect, merely that such inclusion is not determinative of the issue of whether the Company is entitled to a return on the unamortized balance. It appears that witness Maness has misunderstood the Company's position, as is evident from the testimony of witness McManeus, which the Commission also credits. She testified:

> [I]t is important to recognize that rate base represents the amount of funds supplied by investors. Such funds have been advanced for many purposes. Certainly, construction of electric plant is one such purpose, but there are others – for example, to purchase fuel inventory, to provide cash working capital, etc. Further, to accurately determine the amount of investor-supplied funds, one must consider whether any amounts that have been used for such purposes have been advanced by customers, rather than investors. In this particular case, investors have advanced funds to pay for coal ash compliance costs.

Tr. Vol. 6, p. 317. She elaborated further, indicating that the "characteristic that makes the deferred coal ash cost a legitimate component of rate base" is the fact that the funds used to pay those costs were supplied by investors. Id. at 318.

The point of a deferral is that the costs to be deferred are of a magnitude that they need to be taken out of the normal ratemaking accounting process and set to one side for later inclusion in rates, lest the Company lose its ability to recover them. Tr. Vol. 9, pp. 123-24. Should the Company's ability to recover such costs be impaired, it will not be able to earn at its authorized rate of return. Id. at 124. Setting them to one side means that unless a return is allowed, the Company's ability to earn its authorized rate of return is again impaired. Further, if in the process of bringing the deferred costs into rates the costs are amortized over a period of years, not allowing a return on the unamortized costs again impairs the Company's ability to earn at its authorized rate of return. Rates that impair the Company's ability to earn its authorized return are not just and reasonable, unless the Company should be penalized due to mismanagement, for example, and the Commission would act contrary to law were it to order them.

Finally, the Public Staff's notion that costs accounted for in an ARO, at least to the extent they relate to long lived capital assets, are expenses and therefore ineligible to be characterized as "used and useful" is inconsistent with ARO accounting, and also inconsistent with the law. The Commission has already decided that the Public Staff's legal position that "used and useful" property is confined to "plant" is incorrect. It held in the 2018 DEP Rate Case:

> As a matter of law, it is not necessary that something be classified as "plant" in order to be properly included in rate base. Rather, the issue is the source of the funds. In State ex rel. Utils. Comm'n v. Virginia Elec. & Power Co., 285 N.C. 398 (1974) (VEPCO), for example, the Supreme Court held that working capital (which is not "plant") could be included in rate base, so long as it was provided by the utility:
>
> > Like any other business, a public utility must at all times have on hand a reasonable amount of materials and supplies and a reasonable amount of funds for the payment of its expenses of operation. While Chapter 62 of the General Statutes makes no reference to working capital, as such, the utility's own funds reasonably invested in such materials and supplies and its cash funds reasonably so held for payment of operating expenses, as they become payable, fall within the meaning of the term "property used and useful in providing the service" … and are a proper addition to the rate base on which the utility must be permitted to earn a fair rate of return.
> >
> > Conversely, the utility is not entitled to include in its rate base funds which it has not provided but which it has been permitted to collect from its customers for the purpose of paying expenses at some future time and which it actually uses as working capital in the meantime.
> >
> > 285 N.C. at 414-15. As the Company appropriately accounted for coal ash basin closure costs in the working capital section of rate base, and as these funds were investor-furnished, not customer-furnished, VEPCO holds that they are "used and useful" within the meaning of N.C. Gen. Stat. § 62-133(b)(1) in the provision of service. As such, the Company is entitled to earn a return on those funds over the period in which the costs are amortized.

2018 DEP Rate Order, pp. 194-95.

In addition, however, witness Maness is incorrect in his view of the appropriate accounting outcome. He indicates, "It is appropriate to state that the actual costs capitalized by a utility as the costs of used and useful property itself may be included in rate base and thereby earn a return, as long as those costs are reasonable and prudently incurred, and are intended to provide utility service in the present or in the future; however, the expenses of operating and maintaining that property in the present or in the future do not get capitalized as part of the cost of the property." Tr. Vol. 22, pp. 77-78 (emphasis added.) It is less than clear what witness Maness means by this qualification.

However, as witness Doss testified, in ARO accounting, "Under both GAAP and FERC guidance the asset created when a Company initially recognizes an ARO is considered part of the property, plant and equipment for the assets which must be eventually retired." Tr. Vol. 12, p. 71 (emphasis added.) Accordingly, such costs are used and useful in that they are intended to provide utility service in the present or in the future through achieving their intended purpose: environmental compliance, the retirement of the ash impoundments and the final storage location for the residuals from the generation of electricity. As witness Doss concluded, "The achievement of those three purposes is used and useful as the utility has the obligation to comply with CAMA and the CCR Rule." Id. at 73.

When the coal ash basins at issue in this matter were constructed, they were capital assets "used and useful" in the provision of service to customers – their function was to store coal ash, a byproduct of the generation of electricity. Even if closed as a result of CAMA and the CCR Rule, the basins at all but high priority sites will remain, although they may be capped in place or have other remedial measures taken to comply with the current regulatory requirements. As such, they will remain used and useful, because they will still store coal ash, a byproduct of electricity generation. The basins at high priority sites will no longer exist, but in the case of Dan River, a new landfill is being constructed, which is a capital asset and used and useful – it, too, will store coal ash. The landfill will have a long-lived synthetic liner, a cost that even outside the concept of ARO accounting is not an "expense." Other expenses of a more O&M or general administration variety were incurred yet deferred under the deferral orders of this Commission, meaning that the Company is afforded the opportunity to recover them in rates at a later time. The funds used to pay for those costs were furnished by the Company and its investors, and the costs are eligible for a return on, not merely a return of, those funds, lest its earnings be impaired. In this sense, just like "classic" working capital, these funds are "property" of the Company, used and useful in the provision of electric service to its customers. Such funds, properly accounted for in an ARO, are eligible "deferral and amortization and for earning on the unamortized balance." The Commission so orders in this case.

The question to be decided is the amount of the funds so eligible. That depends upon the Commission's analysis of the reasonableness and prudence of the costs incurred.

5. Procedure for Establishing the Deferral

The AGO, in its brief, argues that establishment of the ARO is unlawful on several grounds. The AGO argues that the 2015-2017 CCR remediation costs accounted for in the ARO if recovered through rates constitute retroactive ratemaking. The AGO argues that the deferral should not be permitted because DEC failed to obtain prior approval. The AGO argues that deferral of the CCR remediation costs does not meet the test established by the Commission because DEC has not shown that its earnings would have been sufficiently harmed when the ARO was established.

As to the assertion of retroactive ratemaking, the fundamental purpose of creating a deferral is to recognize that the costs were not being recovered in rates when incurred. Moreover, the test period in this case is the 12 months ending December 31, 2016 adjusted for known and measurable charges through December 31, 2017. Consequently, many of the costs are within the test period as adjusted. As to the 2015 costs, the Commission determines they along with subsequently incurred costs have been properly deferred for recovery in this case, were extraordinary when incurred, and were not being recovered in rates in effect at the time incurred. DEC notified the Commission of its decision to establish the ARO in December 2015 and sought permission to defer in December 2016. The AGO commented on the DEC request and did not object to the timing of the request.

The Commission customarily requires contemporaneous approval of deferral accounting for extraordinary expenditures incurred between general rate cases. The Commission prefers this procedure over efforts to recover pre-test year costs recovery in the general rate case where no contemporaneous approval had been sought. This is not a case where DEC failed to seek contemporaneous approval. DEC sought deferral in 2016 after giving earlier notification in 2015. It was in 2016 that the Company had information permitting a quantification of the costs at issue. Just as a utility cannot request prior approval of extraordinary storm damage costs before the storm occurs, no requirement exists of pre-event approval of CCR costs such as these - only reasonably contemporaneous approval, and the Commission has waived even this requirement in the past. See Order Granting General Rate Increase, (Dec. 21, 2012), Docket No. E-22 Sub 479, addressing DNCP's request for deferral of costs of the Bear Garden generating plant. Significantly, any AGO complaint as to timing of the deferral request should have been raised at the time DEC sought approval of the deferral. The AGO made no such complaint.

Similarly the AGO's argument that the deferral should be disallowed because DEC's earnings in 2015 and 2016 were such that deferral was unjustified should have been made at the time the deferral was sought. Moreover, the AGO's untimely evidence to support its theory of lack of economic harm to justify deferral is deficient. The AGO has referred to surveillance reports showing what DEC was earning in 2015 and 2016. These are returns that do not reflect the CCR remediation costs. DEC's December 21, 2015 notification of ARO accounting and its surveillance reports expressly state that the ARO costs are not reflected. Without showing what the returns would have been without deferral, the surveillance report returns tell little about the financial justification for the deferral. Moreover, 2016 is a test year. Financial data fully adjusted after general rate case changes should be used if looking backward at what DEC's earnings were in 2016. The Commission determines that the CCR remediation in the ARO were properly deferred and that the costs so deferred are appropriately amortized over five years and that the unamortized portion is eligible for a return.

6. The Public Staff's Specific Cost Disallowance Proposals

The Commission must undertake a detailed analysis before any costs can be disallowed on the basis of findings of imprudence. 1988 DEP Rate Order, p. 15. The Public Staff undertook such an analysis of the Company's coal ash costs, and based on that analysis presented three discrete and specific proposed sets of disallowances. Two were presented through witness Junis: first, $2,109,406 of legal expenses associated with the defense of litigation matters regarding alleged environmental violations and, second, $2,352,429 reflecting groundwater extraction and treatment costs that witness Junis asserted exceed what CAMA would have required absent alleged environmental violations. Finally, Public Staff witnesses Garrett and Moore recommended a disallowance totaling $97,698,274 relating to the cost of the Company's compliance activities at Buck, Dan River, Riverbend, and W.S. Lee, on the grounds that those activities were more costly than other reasonable alternatives.

a. Junis: Alleged Environmental "Violations"

The Public Staff, through witness Junis, asserts that disallowance of the Company's litigation expense and groundwater costs is justified because these costs flow from "violations" of the law. Tr. Vol. 26, pp. 728-34. For the reasons discussed below, the Commission based on its assessment of the evidence and in the exercise of its discretion determines not to authorize the Public Staff's proposed disallowances of legal expense and groundwater extraction and treatment costs. The evidence does not support a finding that DEC violated the law (with the exception of the federal plea agreement, the costs related to which are not at issue here), nor does it support a finding of imprudence with respect to these costs.

i. Junis: Legal Expenses

Witness Junis cites the Glendale Water case (State ex rel. Utils. Comm'n v. Public Staff, 317 N.C. 26, 343 S.E.2d 898 (1986)) for the proposition that the legal expense should be excluded. In that case, the North Carolina Supreme Court held that legal expense associated with a penalty proceeding in which the utility had been found to have violated the law should be excluded. Witness Junis suggests that the same rationale would apply to his exclusion of the Company's litigation expense related to what he terms DEC's failure to comply with environmental laws and regulations. He claims that "compelling evidence" of such violations is shown by the SOCs and DEQ reports of exceedances. Tr. Vol. 26, pp. 728-29.

The distinction between this case and Glendale Water is that, with the exception of the federal plea agreement with respect to the Dan River spill and Riverbend (for which the Company is not seeking to recover any costs of penalties and fines), there is no finding in the other litigation brought against the Company, or admission by the Company in that litigation, that any "violation" actually occurred. No Intervenor introduced evidence in this case that any "violation" actually occurred. Witness Junis' testimony that the Company's legal expenses for state litigation of coal ash complaints resulted from "violations" is based on the DEQ reports of groundwater exceedances and the fact that DEC sought SOCs to address seeps at the Allen, Marshall, and Rogers (Cliffside) stations, both of which Junis interprets as "compelling evidence of DEC's violations." Tr. Vol. 26, pp. 730-31.

The Commission determines that the facts of this case are distinguishable from Glendale Water. Litigants settle disputed matters frequently for many reasons that are unrelated to the settling parties' underlying view of the merits of the dispute. In this case, for example, the Company and the Public Staff have entered into a Partial Settlement which includes a rate of return on equity of 9.9% (versus the Public Staff's recommendation of 9.1%), and a capital structure of 52% equity and 48% debt (versus the Public Staff's recommendation of 50/50). This settlement, which the Commission has approved, therefore results in millions of dollars paid by customers over and above the Public Staff's pre-settlement position, but that does not mean that the Public Staff somehow ceased to believe in that pre-settlement position. It means that the Public Staff, on balance, determines that its constituency (the using and consuming public) is better off with the Partial Settlement than without, despite the fact that the rate of return on equity and capital structure provisions of the settlement will cause increased rates. Likewise, an SOC is a regulatory mechanism intended to provide clarity and certainty with respect to scope and schedule for compliance-related activities given a change in circumstances, such as a change in requirements or in operations. The Company's willingness to enter into an SOC, therefore, is not premised upon an underlying admission of culpability. Furthermore, as explained by witness Wells, a DEQ report of an exceedance does not equate to a violation of environmental law or regulation.

Witness Junis has attempted to expand the applicability of Glendale Water by applying its holding beyond a litigated finding of liability to include (1) resolutions of complaints that do not involve any finding of liability and (2) pending legal claims of environmental violations, where there is "compelling evidence of environmental violations." Tr. Vol. 26, pp. 729-30. The Commission disagrees with the Public Staff position. Glendale Water applies where there is a finding of liability and the Commission declines to extend its holding further. In addition, the Commission does not find DEQ exceedance reports or SOCs to constitute compelling evidence of environmental violations.

The Commission determines, as it did in the 2018 DEP Rate Order, that entering into a settlement does not equate to an admission of guilt or wrongdoing. 2018 DEP Rate Order, p. 180. Conflating the existence of a settlement agreement or an SOC with an admission or other proof of guilt or wrongdoing is inconsistent with both the law and public policy of North Carolina. The North Carolina Rules of Evidence, for example, prohibit parties from using the existence of a settlement as evidence of liability.[73] Likewise, in

[73] N.C. R. Evid. 408 ("Evidence of (1) furnishing or offering or promising to furnish, or (2) accepting or offering or promising to accept, a valuable consideration in compromising or attempting to compromise a claim which was disputed as to either validity or amount, is not admissible to prove liability for or invalidity of the claim or its amount. Evidence of conduct or evidence of statements made in compromise negotiations is likewise not admissible.").

other matters before the Commission, the Public Staff has defended the regulatory policy of encouraging reasonable and prudent settlements. In 2016, NC WARN filed a Petition for Rulemaking seeking to require settlements between the Public Staff and utilities to be made open to the public. Tr. Vol. 12, p. 156-34; see also Order Declining to Adopt Proposed Settlement Rules, Docket No. M-100, Sub 145 (Mar. 1, 2017) (Settlements Order). 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 reducing litigation expenses that would otherwise be recoverable by utilities as a component of the cost of providing utility service.

Tr. Vol. 12, p. 156-35. See also Settlements Order, p. 3.

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. Tr. Vol. 12, p. 156-35. See also Settlements Order, p. 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)). The Public Staff relied on the principle 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 sufficient consideration but upon the highest consideration of public policy as well." Tr. Vol. 12, p. 156-35 (quoting Knight, 131 N.C. App. at 262, 506 S.E.2d at 731 (emphasis added) (internal quotations omitted)). As in the 2018 DEP Rate Order, the Commission again determines not to approve a disincentive to settle pending or future lawsuits. 2018 DEP Rate Order, p. 180. The Commission therefore rejects the Public Staff's proposed disallowance of the Company's legal.

ii. Junis: Groundwater Treatment Costs

Similar considerations apply to the groundwater extraction and treatment costs witness Junis seeks to disallow, which he characterizes as costs to remedy environmental violations that exceed what CAMA would have required absent such violations. He cites as examples of such costs those resulting from (1) the DEQ Settlement Agreement (also referred to as the Sutton Settlement), which Junis contends result in costs greater than would have been necessary to pay for CAMA compliance without violations, and (2) resolutions of lawsuits alleging environmental violations where the outcome involves remedial action that costs more than the risk classification warrants, and "compelling evidence" shows the outcome resulted from environmental violations. Tr. Vol. 26, pp. 731-32. Witness Junis applies this theory of disallowance to include the Company's expenditures for groundwater extraction and treatment at Belews Creek, made pursuant to the September 2015 Sutton Settlement between DEQ, DEC, and DEP. See Junis Exhibit 29, Official Exhibits Vol. 26 (DEQ Settlement Agreement). He also applies this theory to include the Company's expenditures for selenium removal equipment at the Riverbend plant. Tr. Vol. 26, pp. 733-34.

Consistent with the 2018 DEP Rate Order, the Commission again declines to find that the DEQ Settlement Agreement evidences violation of environmental obligations. The DEQ Settlement Agreement references in its recitals a DEQ "Policy for Compliance Evaluations" promulgated in 2011, and it appears from the recitals and their description of that Policy that there was a very serious question as to whether any violation of the State's groundwater standards had occurred. See DEQ Settlement Agreement, at 3, 4-5. The recitals also indicate, with the passage of CAMA, that the Company would be required to close its coal ash basins, and that CAMA "dictate[d], in detail a procedure for assessing, monitoring and where appropriate remediating groundwater quality in areas around coal ash impoundments in North Carolina …." Id. at 3-4. Further, in the recitals the DEQ acknowledged that the CAMA requirements were "designed to address, and will address, the assessment and corrective action" associated with alleged groundwater contamination. Because CAMA would require the Company to implement certain actions, the Commission determines as it did in the 2018 DEP Rate Order (see 2018 DEP Rate Order, p. 181) that it was reasonable for the parties to settle irrespective of whether the Company had committed violations of 2L Standards. Had the Company continued to litigate the matter in this circumstance, its actions may have been deemed by the Public Staff and this Commission to be imprudent, with a disallowance of the legal costs incurred in connection with continued litigation.

The Commission finds the testimony of Company witnesses Wells and Kerin to be instructive with respect to the Public Staff's proposed disallowance of groundwater treatment costs, and entitled to substantial weight. Witness Wells' testimony demonstrates that DEC has in most instances adequately managed its coal ash and that the Company's management and appropriate responses to seeps and groundwater issues do not equate to environmental violations. Witness Kerin's testimony demonstrates that costs related to groundwater extraction and treatment at Belews Creek and its purchase of wastewater treatment equipment at Riverbend were reasonable and prudent and are recoverable.

Witness Wells testified that exceedances of groundwater standards and the existence of seeps in the vicinity of the Company's ash basins do not indicate mismanagement or poor compliance programs. He explained that the existence of groundwater exceedances at or beyond the compliance boundaries at DEC sites is rather a function of where these sites are on the timeline of groundwater assessment and corrective action under modern laws that have changed the way unlined basins are viewed. He testified further that the Company's decision to use unlined basins to treat ash transport water was reasonable and consistent with the approach consistently employed across the power industry at the time that the basins were built, and noted that each DEC site had been properly and legally operating an unlined basin for at least a decade before the adoption of any regulatory requirements related to groundwater corrective action. He stated that as requirements changed over time, DEC has taken action required by DEQ's groundwater rules, and later by CAMA and the federal CCR Rule, to address groundwater impacts as they have been identified. As he noted, witness Junis did not contend that either DEC or the state of North Carolina was an outlier by using unlined basins during this timeframe, and no such contention could reasonably be made given well-published facts about coal power generation practices at that time. Tr. Vol. 24, pp. 227-29, 233, 236, 258.

Witness Wells adequately rebutted the Public Staff's suggestion that DEC only engaged in comprehensive groundwater monitoring and remediation when forced to do so by CAMA and other developments. He testified that the Company began monitoring groundwater at Allen in 1978, Belews Creek and Marshall in 1989, Dan River and W.S. Lee Steam Stations in 1993, and the remaining sites in or around 2006. He noted that, in 2011, DEQ prescribed a process to be undertaken by DEQ and utilities upon the identification of a groundwater exceedance near a coal ash pond, which included performance of an assessment to determine the cause of the exceedance and, as necessary, develop a Corrective Action Plan consistent with North Carolina groundwater rules. He stated that under that process, only after a utility failed to undertake corrective action when directed to do so would DEQ consider pursuing enforcement. He noted that, in contravention of witness Junis' testimony, all of this activity predates the threat of litigation by environmental groups, the DEQ enforcement suit, the Dan River spill, and CAMA. He also testified that, as witness Junis' testimony and exhibits demonstrate, DEC has always promptly responded to any concerns raised by the relevant regulatory entities and where necessary, implemented appropriate corrective action steps to remedy any issue. He stated that the Company has proactively sought consent orders and written agreements to ensure alignment with the regulatory agency as to appropriate scope and timing of additional investigation and corrective action. Tr. Vol. 24, pp. 230-31, 234-36, 259-60.

Witness Wells also disagreed with the Public Staff's suggestion that any exceedance or violation of water quality regulations, no matter how minor or how long ago, leads to the denial of cost recovery for any activity that acts to "cure" the impacts of the violation. In addition to reiterating that not all exceedances of the 2L standards amount to a violation that requires corrective action under the 2L rules, witness Wells stated that even when an exceedance requires corrective action, the groundwater rules do not treat the exceedance the same way as, for example, the Clean Water Act treats an exceedance of an NPDES permit limit. When the latter is violated, he explained, the permittee is immediately subject to an NOV and penalty, and must ensure the next discharge complies with the permit limit or risks a new NOV and escalating penalty. Tr. Vol. 24, pp. 244-45.

Witness Wells contrasted this process with groundwater standards, under which an exceedance does not immediately result in an NOV and escalating penalty. Instead, he explained the owner/operator must report the exceedance and work with the DEQ to determine whether it was due to permitted activity, assess the extent of the exceedance, and undertake corrective action. Any newly measured exceedances do not require a further site assessment and do not result in additional or escalating penalties, but are actually expected as an additional assessment prior to corrective action is conducted. He testified that the 2L rules' corrective action provisions are deliberately designed around the idea that older facilities, built before liners were a regulatory obligation, were likely to have associated groundwater impacts, that such impacts were not the result of regulatory noncompliance, and that they should be addressed in a measured process. He concluded that compliance with this process is not mismanagement and should not be held against DEC with respect to cost recovery. Tr. Vol. 24, pp. 245-46. The Commission agrees.

The Commission is further persuaded by witness Wells' testimony that witness Junis' characterization of groundwater violations under the 2L rules ignores the iterative nature of comprehensive site assessment. He noted that measuring exceedances at different locations in a plume around an activity may result in multiple exceedances of groundwater standards, but that does not result in multiple violations of the 2L rule's prohibition. He explained that this distinction is important for evaluating the claim that the number of exceedances indicates a "breadth of environmental violations." It would be more accurate to say, he explained, that, at seven sites, DEC has lawfully operated ash basins that, after decades of use, resulted in exceedances of groundwater standards at those sites. He pointed out how Duke Energy's coal ash basins are some of the most studied sites in North Carolina, with more than 1,400 groundwater monitoring wells, and that the number of exceedances presented by witness Junis signifies therefore the thoroughness of the evaluation rather than a number of groundwater violations. Tr. Vol. 24, pp. 238-41, 260-61. The Commission notes in particular witness Wells' testimony at the hearing that the iterative (and difficult) nature of monitoring groundwater impacts is illustrated by the fact that two wells located a short distance from each other could present very different conditions, including different naturally occurring constituents. Tr. Vol. 26, pp. 91-93.

Witness Wells also persuasively argued that the groundwater extraction and treatment costs that witness Junis recommended for disallowance relate to activity that DEC agreed to undertake pursuant to the DEQ Settlement Agreement to accelerate, but that would have been required in the normal course as part of the groundwater correct action under the CCR Rule and CAMA. Tr. Vol. 24, p. 241. Although CAMA borrows heavily from the 2L Rules, including by incorporating the substance of its corrective action requirements, one key difference between the two laws is that CAMA's groundwater assessment and corrective action provisions are triggered by <u>exceedances</u> – not <u>violations</u> – of the 2L groundwater standards.[74] In other words, unlike the 2L Rules, CAMA requires utilities to perform groundwater assessment and corrective action for all identified exceedances of the 2L groundwater standards regardless of whether the exceedance amounts to a violation of the applicable groundwater standard.

The Commission is also persuaded by the evidence presented by Company witness Kerin in response to the Public Staff's position, which shows that the groundwater treatment wells installed at Belews Creek would have been installed even without the DEQ Settlement Agreement, because while the time frame for that installation was moved

[74] <u>Id.</u>; <u>see</u> <u>also</u> N.C. Gen. Stat. § 130A-309.211. When preparing a corrective action plan, CAMA does not require the utility to describe any 2L violation and instead required only a "description of all exceedances of the groundwater quality standards, <u>including any exceedances that the owner asserts are the result of natural background conditions</u>." N.C. Gen. Stat. § 130A-309.211(b)(1)a (emphasis added).

up pursuant to the Agreement, the Company would have installed the wells in order to comply with CAMA even absent the Agreement. Tr. Vol. 24, p. 117.

Based on the credible and persuasive testimony of the Company's witnesses, the Commission determines, with exceptions addressed below, that there is insufficient evidence that DEC would have had to engage in any groundwater extraction and treatment activities absent the obligations imposed upon it by CAMA and/or the CCR Rule. Witness Wells' testimony in particular shows that the assertion that DEC's "violations" resulted in the DEQ Settlement Agreement and in groundwater extraction and treatment costs that would not otherwise have been incurred is incorrect and not supported by the evidence.

The Commission determines that Witness Kerin also successfully rebutted witness Junis' position that the cost of equipment to remove selenium at Riverbend should be disallowed. He explained that it was imperative for the Company to have a system to appropriately treat the site wastewater and to meet future permit selenium limits. He also noted that while this system is important for those reasons, because it is also expensive to operate, the Company will only use it when other physical and chemical extraction methods are insufficient. He emphasized the prudency of having this system in place should it be needed, in order to avoid the need to cease ash removal operations if selenium levels increased and no bioreactor was on site. He noted that such a delay would cost the Company millions of dollars of delay charges. Tr. Vol. 24, pp. 90, 117-19, 132. The Commission agrees that it was reasonable and prudent for the Company to purchase the bioreactor system to mitigate against potential violations of permit limits and declines to accept witness Junis' recommended disallowance of these costs.

No party disputes the reasonableness of the amount of groundwater assessment and treatment costs the Company seeks to recover in rates. The dispute relates instead to the fact that the groundwater assessment and treatment costs were incurred pursuant to a settlement with DEQ and in response to DEQ reports. The testimony of witnesses Kerin and Wells demonstrates that these costs – amounting to $2,352,429 – were reasonably and prudently incurred to comply with the Company's obligations under CAMA and the CCR Rule. The Commission determines that they therefore are recoverable in rates, as are the $2,109,406 in legal fees that witness Junis also proposed excluding.

The AGO, Sierra Club, and other Intervenors make similar arguments to the Public Staff that DEC has failed to keep pace with industry standards and should therefore not be allowed to recover current environmental compliance costs in rates. As in the DEP case, these Intervenors argue that the Company should have done more, in contradiction to other witnesses that DEC should have done less, than just comply with the current environmental regulations at the time.

As an initial matter, based upon the evidence presented in this case, with the exception of the federal criminal case to which DEC pled guilty, the Company has not been found liable for violations of the law. As stated above, the Commission will not use settlement agreements to find liability. The AGO witness asserts that the Commission should consider all of the seeps located at DEC's ash basin sites and deny recovery of CCR costs except – as clarified at the hearing – those which are incurred to comply with the CCR Rule. However, as stated in the criminal case that covered engineered seeps, DEQ and DEC have been in long-standing negotiations as to whether seeps are a violation of the law and since 2014, whether seeps should be covered by the NPDES permit. AG-Kerin Direct Cross Examination Exhibit 6, pp. 78, 95; AG-Kerin Direct Cross Examination Exhibit 5, p. 44. According to statements made in the criminal case, DEQ has currently not made a determination on this issue. AG-Kerin Direct Cross Examination Exhibit 5, p. 44.

In addition, the Commission finds the testimony of Company witness Kerin informative as to Intervenors' claims. Witness Kerin explained that the securities filings cited by AGO witness Wittliff simply notified the SEC of potentially significant coal ash costs that Duke Energy anticipated at that time, and potential new regulatory contingencies to which it could become subject; they were not intended to analyze the Company's coal ash management practices and do not support any claim that such practices were out of step with industry, much less that DEC was aware of any such inconsistency. Witness Kerin also rebutted the AGO's assertion that the Company should have built new lined impoundments rather than expand existing unlined impoundments, citing the significant expense that new lined impoundments would entail, while not eliminating the obligation to maintain existing unlined impoundments. He pointed out that such action would have put the Company at risk of disallowance of costs. He recalled witness Wittliff's testimony in the DEP proceeding that utilities continued to use unlined wet ash impoundments because the law continued to allow them to do so, and noted the inconsistency between admitting that such a practice was legal and asserting that it was also imprudent. Witness Kerin also enumerated the ways in which the Company has practiced dam safety and explained that the five-year dam safety inspections demonstrate careful monitoring of issues as well as a lack of any major issue threatening dam integrity. Tr. Vol. 24, pp. 119-24. For many of the same reasons, witness Kerin demonstrated the inaccuracy of Sierra Club witness Quarles' assertions regarding the consistency of the Company's coal ash management practices with industry standards and the costs of lined landfills as opposed to surface impoundments. Tr. Vol. 24, p. 91.

The limitations of the Intervenors' and the Public Staff's approach is the fact that the kinds of actions they appear to have favored – such as lining ash ponds when others in the industry were not lining them, or creating dry ash basins when the Company's industry peers were sluicing coal ash into wet basin impoundments, would (a) have increased costs that would have been charged to customers, or (b) would have left the Company open to credible claims of "gold-plating," and therefore cost disallowance, which would have prevented the Company from moving forward with these suggested improvements in the first place. These parties advance inconsistent positions. They fault the Company for not undertaking steps that others were not, but at the same time disavow any responsibility of paying for that which they – in 20/20 hindsight – wish the Company had undertaken. As noted at the hearing during questioning of Company witness Wells, these parties criticize the Company's coal ash management practices dating back decades, yet took no actions themselves to address coal ash until within the past five years. For all of these reasons and based on the evidence presented, the Commission is not persuaded, with exceptions noted below and later in this the order, that any past violations by DEC, or many of its past coal ash management practices, support the discrete amounts of cost disallowances advocated by the Intervenors and the Public Staff in this case.

The AGO and the Sierra Club further assert that all of the coal ash closure costs are the result of unlawful discharges and are not recoverable pursuant to N.C. Gen. Stat. § 62-133.13. The Commission rejects the AGO and Sierra Club's reading of N.C. Gen. Stat. § 133.13. The costs being incurred are not resulting from an unlawful discharge as defined by the statute, which is a discharge that results in a violation of State or federal surface water quality standards. Rather, DEC is incurring the costs to comply with the federal CCR rule and CAMA.

Lastly, with respect to the bottled water expense DEC is seeking cost recovery of, although no party requested a specific disallowance for the cost of bottled water, the Commission finds that DEC shall remove from its request for recovery any costs for bottled water.[75]

b. Garrett and Moore: Overview

The Public Staff, through witnesses Garrett and Moore, asserts that the Company acted imprudently and unreasonably with respect to the management of CCRs from the Buck, Dan River, Riverbend, and W.S. Lee Plants, and contends that the Company should have selected different management approaches, thereby saving costs. The Public Staff recommends that a $10,612,592 disallowance be applied with regard to Buck Plant ash (Tr. Vol. 21, p. 61), a $59,320,890 disallowance be applied with regard to the Dan River Plant ash (Tr. Vol. 21, p. 67), a $489,600 disallowance be applied to Riverbend Plant ash (Tr. Vol. 21, p. 74), and that a $27,275,192 disallowance be applied with regard to W.S. Lee ash (Tr. Vol. 21, pp. 34-34), for a total recommended disallowance of $97,698,274.

The Commission determines not to accept this discrete disallowance, based upon the testimony of Company witness Kerin, which the Commission credits and to which the Commission attaches substantial weight. In the 1988 DEP Rate Order, this Commission stressed the importance of carefully examining the Company's explanations of the decisions it made, as of the time they were made, and emphasized the credibility of the decision-makers, particularly in juxtaposition to after-the-fact analyses presented by Intervenor-retained consultants. See, e.g., 1988 DEP Rate Order, p. 29. The Commission does not question the bona fides or expertise of Garrett and Moore. The Commission is persuaded, however, by witness Kerin's testimony that Garrett and Moore missed or overlooked pertinent facts and real world conditions in their recommendations, and that

[75] The total amount spent on bottled water through the end of August 2017 is $1,606,185. These costs include the bottled water itself, the delivery company and personnel associated with the delivery, and the consulting firm that is managing the overall bottled water delivery program for Duke Energy. Tr. Vol. 14, pp. 220-21.

their discrete disallowances are therefore unwarranted. Witness Kerin's testimony regarding the Company's decisions is entitled to substantial weight – more weight than after the fact evaluations from Garrett and Moore. Witnesses Garrett and Moore's recommended disallowances were challenged at the hearing through cross-examination. These witnesses were unable effectively to support their positions while on the witness stand. The Commission determines their recommendations deficient on the basis of a lack of credibility. In this regard, the Commission is not persuaded to discount witness Kerin's testimony by witness Wittliff's challenges to witness Kerin's expertise. As concluded in the 2018 DEP Rate Order, witness Kerin has "lived" this project since its inception (2018 DEP Rate Order, p. 187), and demonstrated competent understanding of the subject in pre-filed testimony and at the hearing. Witness Witliff's testimony from the witness stand likewise suffered from a lack of credibility.

i. Moore: Location of On-Site Landfill at Dan River

Witness Moore asserted that, while he agreed with DEC's decision to construct an on-site landfill at Dan River, he disagreed with the Company's chosen location for the onsite landfill. Tr. Vol. 21, pp. 90-91. Instead of locating the landfill within the footprint of the Ash Fill areas – which required first excavating and transporting off-site ash from those area – witness Moore contended that DEC should have considered locating the landfill along the western property boundary of the site, Id. at 91-92, even though he conceded that the CAMA moratorium prohibited construction of new or expanded CCR landfills located wholly or partly on top of the Primary Ash Basin, Secondary Ash Basin, and the Ash Fill 1 and 2 areas. Tr. Vol. 24, p. 94. Witness Kerin's rebuttal testimony demonstrates that witness Moore's proposal was not feasible in the time frames available to the Company, and in likelihood impossible from an engineering perspective.

Witness Moore illustrated his proposed landfill site location with a chalk-line, ovaloid drawn on top of an existing jurisdiction water designation map for the Dan River Plant. Tr. Vol. 21, p. 44; Moore Direct Exhibit 4. This drawing is the totality of the engineering work papers and documentation offered in support of his proposal in his direct testimony. Tr. Vol. 21, p. 92. To agree with witness Moore's recommended disallowance, the Commission would have to conclude that DEC should and could have constructed his proposed landfill in compliance with North Carolina law. The Commission cannot reach that conclusion based on the dearth of supporting documentation from witness Moore regarding his proposed landfill, as well as the volume of evidence presented by witness Kerin in opposition to witness Moore's suggestion. An alternative proposed action must have been feasible in order to be a valid alternative. 1988 DEP Rate Order, p. 15.

Witness Moore admitted that he did not conduct a site suitability study for his proposed landfill location, nor did he conduct a hydrogeologic study of the conditions at the western portion of the Dan River Plant property. Both studies are required under North Carolina law before a landfill can be permitted or constructed. See 15A N.C. Admin. Code 13B §§ .0503-.0504. He did not analyze soil borings of that area of the property, did not visit the portion of the property where he proposed siting the landfill, despite having the opportunity to do so when he made a site visit to the property, and did not make an attempt, at the time he submitted his direct testimony, to calculate the height of his proposed landfill. Tr. Vol. 21, pp. 92-93. Witness Moore only did this after witness Kerin filed his testimony. Tr. Vol. 22, p. 26. His testimony and workpapers, or lack thereof, would not satisfy North Carolina's landfill permit application requirements, let alone justify construction of his landfill.

The Commission concludes that DEC engineers reached the reasonable and prudent decision to reject the western portion of the property as a feasible location for an onsite landfill. As witness Kerin discussed in his rebuttal testimony, there are many engineering and other obstacles to the construction of an onsite landfill along that portion of the property.

First, construction of witness Moore's proposed landfill would have required excavation of an LCID Landfill containing asbestos. The fact that the LCID Landfill contained asbestos was not known to witness Moore when he filed his testimony, but could have been discovered had he pulled the publicly available permit for that landfill. Tr. Vol. 21, pp. 97-99. In his direct testimony, witness Moore suggested that the LCID Landfill could have been excavated and transported to the Rockingham County Landfill. As the Rockingham County Landfill no longer accepts asbestos, witness Moore conceded that his proposal with regard to the LCID Landfill was no longer possible. Tr. Vol. 21, p. 99. Even if there was a location that could accept the materials containing asbestos in the LCID Landfill, the Commission is persuaded by witness Kerin's testimony that it was prudent for the Company to avoid unnecessarily exposing workers or neighbors to asbestos by locating the onsite landfill in a location that would have required excavation of the asbestos. Tr. Vol. 24, pp. 97-98.

Witness Moore's proposal was also infeasible in that it would have significant wetland and stream impacts as compared to the minimal impacts to streams and wetlands posed by the Company's chosen onsite landfill location. Witness Moore's testimony gave too little attention to stream and wetland impacts, suggesting that mitigation of on-site streams is not uncommon to allow for construction of landfills. Tr. Vol. 21, p. 65. However, witness Moore made no attempt in his testimony to identify the stream and wetland impacts, to prepare a permitting timeline for those impacts, or to analyze the likelihood that those impacts could be permitted. As witness Kerin stated in his rebuttal testimony, and witness Moore acknowledged during live testimony, the U.S. Army Corps of Engineers (Army Corps) will conduct an alternatives analysis demonstrating the practicality of other options that would not impact streams or wetlands, and that permit applicants are required to avoid and minimize aquatic resource impacts to the maximum extent practicable. Tr. Vol. 21, pp. 104-05; DEC-Garrett and Moore Cross Ex. 1, Tab 6; Tr. Vol. 24, pp. 98-100. As compared to witness Moore's proposal, the Company's selected landfill location avoided and minimized impacts to onsite streams and wetlands. Therefore, permitting witness Moore's selected location for stream and wetland impacts would have been challenging based on the Army Corps' alternative analysis criteria. In order to meet CAMA's deadlines, it was reasonable and prudent for DEC to avoid the permitting uncertainty created by witness Moore's proposal by avoiding impacts altogether.

Witness Moore's proposal raises additional permitting uncertainties. Witness Kerin testified that the stream combination on the western and southern sides of witness Moore's proposed landfill would have required the Company to obtain a new construction permit to construct an industrial NPDES outfall through the service water pond, and that both the permit and the outfall would have required substantial time to obtain and construct. Both the new permit and outfall would have to be in place before construction on the landfill could begin, potentially jeopardizing compliance with CAMA's deadlines. The CAMA deadlines provide the overarching framework by which prudency must be assessed. 2018 DEP Rate Order, p. 185. In addition, witness Kerin noted that the 100-year flood plain in this area intrudes into portions of witness Moore's proposed location, and would present additional permitting challenges and likely not leave sufficient space for required stormwater management features on the site. Tr. Vol. 24, pp. 100-02. Witness Moore did not dispute these conclusions.

The evidence shows that had witness Moore visited the site of his proposed landfill, he would have confronted dramatic elevation changes and other topographical features, such as steep slopes, that would have made his proposed site difficult. Further, had witness Moore conducted a site suitability or hydrogeologic study, he would have discovered that the depth to bedrock on the western portion of the property is fairly shallow, leaving little room for excavation for fill volume, borrowing soil or buffering to groundwater. While witness Moore agreed that a landfill owner should minimize potential impacts to neighbors, wetlands, and dangerous materials as much as possible, (Tr. Vol. 21, p. 108), the above site-specific conditions unique to the western property boundary, which witness Moore did not consider in his analysis, would have resulted in a landfill that was in the neighbors' line of sight and more intrusive than the Company's selected location. Tr. Vol. 24, pp. 100-02.

DEC's decision to minimize impacts to neighboring properties in siting its onsite landfill was consistent with an agreement that the Company would ultimately reach with the City of Eden regarding the Dan River site. As a condition of allowing DEC to construct an onsite landfill, the City of Eden required that the landfill be located near the existing basins, and as remote from residential areas as feasible. Tr. Vol. 21, p. 106; DEC-Garrett and Moore Cross Ex. 1, Tab 7. Witness Moore did not dispute the City of Eden agreement's conditions. Tr. Vol. 21, p. 107-08. The nearest location to the existing basins is within the footprint of the former ash stack, and this is the location DEC chose for the landfill. This choice also minimized impacts to surrounding properties by ensuring that the landfill was located as far as feasibly possible from neighboring properties. In contrast, as witness Moore acknowledged, his selected location was not closest to existing basins or as remote as feasible from residential areas. Id. Therefore, had DEC selected witness Moore's proposed landfill location, Mr. Kerin testified, the City of Eden likely would not have approved the zoning required to construct the landfill in this location. See 15A N.C. Admin. Code 13B § .0504(1)(e) (requiring local government approval for construction of a landfill). Witness Kerin stated that, if witness Moore had considered the

City of Eden agreement, he could not have concluded that his alternative landfill location was reasonable or prudent. Tr. Vol. 24, pp. 95-96. The Commission agrees.

Infeasible options do not support a finding of imprudence. 1988 DEP Rate Order, p. 15. Witness Kerin's testimony demonstrates that the Company's actions and real-time decisions regarding the Dan River site were in fact reasonable and prudent, and the costs were prudently incurred. The Commission therefore rejects the Public Staff's proposed disallowance of these costs.

ii. Moore: Buck as Beneficiation Site

Witness Moore contended that DEC should have chosen Weatherspoon over Buck as a beneficiation site, and recommended disallowance of beneficiation costs of $10,612,592 incurred within the test period at Buck. The Commission rejects witness Moore's discrete recommendation. Witness Kerin's testimony shows that witness Moore's analysis is based on a faulty interpretation of CAMA, and that DEC's selection of Buck was reasonable and prudent because it satisfies market demands and maximizes capital investment in the required beneficiation equipment.

CAMA requires the Company 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 <u>installation</u> and <u>operation</u> of an ash beneficiation project at each site capable of annually <u>processing</u> 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." N.C. Gen. Stat. § 130A-309-216 (emphasis added). Witness Kerin testified that DEC satisfied CAMA's requirements by identifying Buck, H.F. Lee, and Cape Fear as the three beneficiation sites based on its conclusion that they offered the most feasible alternative and the best economic value to customers while complying with CAMA. Tr. Vol. 24, pp. 93, 105-08, 131.

At each of the three sites, the Company has contracted to install and operate STAR technology units to process the onsite ash. Tr. Vol. 21, p. 112. The Company has also contracted to sell 230,000 tons of ash from Weatherspoon as aggregate in the manufacture of cement. <u>Id.</u> at 59, 116; Tr. Vol. 24, p. 107.

Witness Moore suggests that the Company could have selected Weatherspoon as a beneficiation site if it had only found a buyer for another 70,000 tons of ash from this location to qualify under CAMA. By selecting Buck, witness Moore contended, Duke Energy supplied an additional 300,000 tons per year of CCR material to the concrete industry, in turn reducing the demand for the 70,000 tons per year of CCR material for the same purposes from Weatherspoon for which Duke Energy was unable to find a purchaser. While the Company agrees that reuse of ash at Weatherspoon is appropriate – and the Company is selling Weatherspoon ash for reuse today – it contends that the Weatherspoon ash would not satisfy CAMA. Based on the testimony of witness Kerin, the Commission agrees.

Contrary to Public Staff witness Moore's suggestions otherwise (Tr. Vol. 21, pp. 111-12), the Commission concludes that the most reasonable reading of N.C. Gen. Stat. § 130A-309-216 indicates that the General Assembly intended that Duke Energy install and operate technology, such as carbon burn-out plants and STAR technology, to process and transform ash to a usable product rather than use the basic drying and screening methods occurring at Weatherspoon. Tr. Vol. 24, pp. 106-07. It is here where witness Moore's theory becomes problematic.

Witness Moore's testimony suggested that the Company's handling of Weatherspoon ash, which does not involve beneficiation processing or much of any processing beyond excavation, would satisfy the CAMA beneficiation requirement. At the hearing, however, witness Moore admitted that the DEP sites chosen for beneficiation under CAMA – Cape Fear and H.F. Lee – and the DEC site, Buck, have and will use the STAR technology to beneficiate ash, and that the ash being sold from the Company's Weatherspoon site is not being beneficiated with STAR technology. He confirmed that installation of a STAR facility to convert ash for cementitious purposes is a reasonable and prudent method of executing the requirements of CAMA, and that ash from the ponds is run through the STAR unit and burned to lower the carbon content of the ash. The process changes the physical and chemical characteristics of the ash, thereby creating a stronger product that can be used in the ready-mix market. Tr. Vol. 21, pp. 111-13, 115; DEC-Garrett and Moore Cross Ex. 1, Tab 12, p. 6. As witness Moore agreed on cross examination, the Weatherspoon ash and the ash that is beneficiated with such technology, as at Buck, are "apples and oranges." Id. at 117.

Witness Moore did not object to Duke Energy's beneficiation approach at H.F. Lee and Cape Fear. Having concluded that installing STAR units at H.F. Lee and Cape Fear was a reasonable and prudent "method of executing the requirements of CAMA," (Id. at 113), the Commission determines that he cannot creditably argue that Duke Energy could have simply excavated, dried, and sold ash from Weatherspoon and still satisfied CAMA's beneficial reuse requirements. Id. at 112. In other words, witness Moore admitted that STAR units accomplish the following: "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." N.C. Gen. Stat. § 130A-309-216. His recommended disallowance, however, in this rate case, depends on a reading of CAMA that does not require installation of a STAR unit or similar technology. The Commission determines that the Public Staff position is inconsistent. The Commission concludes that CAMA contemplates the installation of STAR units or other ash processing technology that changes the physical and chemical characteristics of ash to specifications appropriate for cementitious products.

In addition, witness Kerin pointed out that, even after issuing an RFP, Duke Energy has only been able to secure a buyer willing to enter into a long-term contract for 230,000 tons of ash from Weatherspoon, but not the additional 70,000 tons. Tr. Vol. 24, pp. 105-06. Witness Moore made no attempt to identify a potential buyer for the 70,000 tons. Tr. Vol. 21, pp. 118-19. While the Weatherspoon ash is sold under contract to cement manufacturers and is used as raw material or aggregate in the manufacture of cement, the processed ash from Buck is used as a replacement for cement in concrete. Because these are separate products that are used for different purposes, the sale of beneficiated ash from Buck has no impact on the demand for ash from Weatherspoon. Id. at 105-06. The Commission determines that finding a buyer for 70,000 tons of ash from Weatherspoon would not solve the compliance problem witness Moore identifies. Under his proposal, none of the ash would be processed through a STAR Unit or similar technology, and would therefore not meet CAMA's beneficiation requirement.

The Commission also agrees with the Company that, because CAMA requires the installation of a STAR Unit or similar technology, a cost of approximately $181 million, it was reasonable for the Company to consider the amount of ash available at the site and the potential uses for the ash when making a decision to invest in beneficiation at a particular location. Weatherspoon contains only 2.4 million tons of ash, which is approximately one-third the 6.4 million tons at Buck, so the per-ton cost to process ash at Buck is significantly lower than it would be at Weatherspoon. Additionally, Weatherspoon is in a poor geographic location in relation to the major markets for ash used in the cement industry. Because trucking the ash is part of the cost of the sales, Buck's proximity to Charlotte and Greensboro makes it a much better location for beneficiation, and has the highest revenue projection, followed by Cape Fear (Greensboro and Raleigh) and H.F. Lee (eastern North Carolina and Virginia).

Witness Moore's proposal is not feasible as it would not satisfy the Company's statutory requirement to beneficiate ash. Alternative proposed actions must be feasible in order to truly be alternatives. 1988 DEP Rate Order, p. 15. The Commission cannot, therefore, conclude that the Company was unreasonable or imprudent by selecting Buck over Weatherspoon, and by implementing a beneficiation plan at Buck that does satisfy CAMA.

iii. Moore: Riverbend Off-site Transportation Costs

Public Staff Witness Moore took no exception to DEC's overall ash management plan at Riverbend, including its decision to remove CCR material from the ash stack area or the cinder pit, even though those units are not subject to CAMA or CCR. He did object to DEC's decision to transport and dispose of CCR material from the ash stack to the R&B landfill in Homer, Georgia and to the Brickhaven Facility. Witness Moore recommended that the Commission disallow $489,000 as the premium that was paid to dispose of CCR material from the Ash Stack at the R&B Landfill in Homer, Georgia versus the Marshall Station. Tr. Vol. 21, pp. 72-73.

As witness Kerin noted in his testimony, DEC was required to begin excavation of ash from Riverbend within 60 days of receiving its stormwater permit from DEQ. When DEC received that permit in May 2015, Marshall was not available to accept Riverbend ash. Since DEQ issued the permit on May 15, 2015, DEC had until July 15, 2015 to begin excavating Riverbend ash. While the Company was exploring long-term options to receive the Riverbend ash, it was still obligated to meet DEQ's deadline, and thus it was imperative that the Company contract with a company to haul and dispose of the

Riverbend ash on a short turnaround. Waste Management National Services, Inc. (Waste Management) was able to meet that requirement, and began trucking ash from Riverbend on May 21, 2015, and transported the final load on September 18, 2015. While DEC eventually received approval to dispose of Riverbend ash at Marshall, the Commission is persuaded that DEC would not have been able to send ash to Marshall within the time frames required by DEQ. Tr. Vol. 21, pp. 93, 108-10, 131-32.

Witness Moore's recommended disallowance is based on a "perfect world" scenario where DEC could have accurately predicted permitting uncertainties, such as the dates when DEQ was going to issue the stormwater permit for Riverbend or approval for ash disposal at Marshall. The Commission declines to approve disallowances where the Company promptly achieved compliance with DEQ's 60-day excavation requirement. The Commission uses the CAMA deadlines as the framework by which to assess prudency. 2018 DEP Rate Order, p. 185. The Commission concurs with witness Moore that "[t]he lowest cost option may not always be the reasonable or prudent decision. The determination must be made on a case-by-case basis and the specific factors, obligations, site-specific limitations and other factors known by management at the time." Tr. Vol. 21, pp. 89-90. The Commission concludes that the Company acted reasonably and prudently for the Company to begin excavation at Riverbend as soon as practicable in order to ensure compliance with DEQ's requirements. This decision necessitated finding a temporary disposal solution; therefore, the costs associated with that temporary disposal solution are also reasonable and prudent and should not be disallowed.

iv. Garrett: W.S. Lee Off-site Transportation Costs

The Commission is not persuaded by witness Garrett's testimony that a lower cost option at W.S. Lee was feasible. Like witness Moore's recommended onsite landfill at Dan River, witness Garrett's proposal for W.S. Lee may look viable on paper, but when applied to "real world" conditions, it loses its persuasiveness.

As an initial matter, the Commission agrees with the Company and witness Garrett that DEC's overall ash management plan at W.S. Lee, which includes building an onsite landfill to store ash from the Primary and Secondary ash basins, is reasonable and prudent. Tr. Vol. 21, pp. 25-26. The Commission also agrees that some action was necessary to excavate the IAB or Old Ash Fill to mitigate risk associated with the long-term environmental issues, based on the proximity of the IAB to the Saluda River. The Commission declines to accept, however, witness Garrett's conclusion that delaying excavation of those sites for seven years would have been acceptable to South Carolina regulators or would have eliminated the risk to the Saluda River. Tr. Vol. 24, p. 156.

No dispute exists that DEC's decision to excavate the IAB and Old Ash Fill before the onsite landfill was complete eliminated the geotechnical and environmental risks by November 2017. Tr. Vol. 21, p. 28. Under witness Garrett's plan, ash in the IAB and in the Old Ash Fill would have been left in place and not excavated until the on-site landfill in the secondary ash basin was complete in 2022. Tr. Vol. 21, pp. 129, 130-31. Therefore, the ash would have remained in the IAB and Old Ash Fill an additional seven years until

2022 as compared to the excavation plan DEC undertook. Tr. Vol. 21, pp. 127, 131-32. Under the Company's agreement with SCDHEC, which required excavation of the IAB and Old Ash Fill by December 31, 2017, witness Garrett's seven-year delay was not an option. Tr. Vol. 24, p. 151.

Even assuming witness Garrett's plan was technically feasible and would have resolved the stability issues, implementing his plan would have required trading old risks for new risks. See DEC-Garrett and Moore Cross Ex. 1, Tab 20. Witness Garrett acknowledged during live testimony that the report contained at Tab 20 concluded that if the IAB ash was not removed, danger arose of it's flowing into the Saluda River. Tr. Vol. 21, pp. 135-36. He also acknowledged that in certain areas of the IAB that abut the Saluda River, the steep, 1:1 slopes are covered in trees and vegetation. Id. at 137. Witness Garrett also agreed that trees would have to be removed to execute his proposal, but he did not consider in his analysis how the trees would be removed (with heavy equipment or chain saws) or how tree removal might affect slope stability. Id. at 148-49. He also acknowledged that soft, alluvial clays run beneath the IAB and the steep slopes where his proposed work would occur, and that the dam itself is partially constructed from ash and sandy silt that would also have to be excavated. Id. at 138, 141. Witness Garrett conceded that his work proposal as reflected in Garrett Direct Exhibit 3 is "not a design document" nor is it "specific instruction on how to go about that work." Id. at 141. He also acknowledged the limitations of the S&ME report on which he relies, in that it, too, does not explain practically how a slope stability and grading project would be executed. Id. at 141, 146-47.

The Company provided persuasive evidence in the form of witness Kerin's testimony that witness Garrett's proposed grading and stability project would not have been reasonable or prudent. Witness Kerin testified that the equipment necessary to implement witness Garrett's proposal could not have safely traversed the dike on the downslope of the IAB. Moving the heavy equipment to the downstream/river side of the downslope to excavate silt, ash, sand and trees would have created undue risk to bank stability, worker safety, and risk of an ash release into the Saluda River. Witness Garrett's proposed project would have unnecessarily put worker and environmental safety at risk, and the delay would have been unacceptable to DEC and to the SCDHEC. These new risks were understandably unacceptable to the Company. Tr. Vol. 24, pp. 112-14, 132.

The Commission cannot conclude that witness Garrett's proposal was the more reasonable and prudent option because the Public Staff cannot show, from an engineering perspective, how the work would be practically and safely executed. The Public Staff only presented a concept. To take witness Garrett's plan from concept to reality would require engineering and design plans with specific instructions on how the work would be conducted. Tr. Vol. 21, p. 141. The Public Staff, although armed with an engineering expert, failed to present any such plans. On the other hand, Company witness Kerin credibly provided evidence of the real-world flaws with witness Garrett's concept, from both timing and engineering perspectives.

The Commission concludes that it was reasonable and prudent for Duke Energy to immediately excavate the IAB and Old Ash Fill, in compliance with its agreement with SCDHEC. Duke Energy was able to eliminate existing risks without creating new risks. The Commission declines to second-guess the Company's judgment in that regard. Therefore, because no onsite landfill was available for the disposal of the IAB and Old Ash Fill materials at the time they were excavated, it was also reasonable and prudent for the Company to utilize the R&B landfill in Homer, Georgia for disposal of those materials, and the costs associated with that effort should not be disallowed.

Finally, based on witness Kerin's testimony the Commission agrees that the Company's plan to mitigate future risk of operating two ash management structures, which would be the result if it did not excavate the Structural Fill Area at W.S. Lee in the future, is reasonable and prudent, even though witness Garrett did not suggest any disallowances with respect to this plan. Witness Kerin stated that, in order to resolve the concerns of SCDHEC and environmental groups, the Company agreed to mitigate future risk of operating two ash management structures by managing all ash at W.S. Lee through a single management structure – the landfill – as opposed to taking a piecemeal approach as suggested by witness Garrett. He stated that if the Company was later required to excavate the Structural Fill area after the landfill project was completed, it would incur greater costs than it will incur by managing the ash while the landfill project is ongoing, and that the decision to excavate this area now is reasonable and prudent approach to mitigating against potential future ash related liability and to reduce future costs for the site. Tr. Vol. 24, pp. 93, 116.

7. <u>Conclusion with respect to January 1, 2015 – December 31, 2017 Costs</u>

The Commission finds that the costs are known and measurable, were reasonably and prudently incurred, and to the extent capital in nature are used and useful in the provision of service to customers. The Commission determines the costs were properly deferred. As such, with the exception noted below, they are recoverable from customers. The issue that remains is the amortization period over which this recovery is to be made.

The Commission deems the Company's proposal, which submits that the amortization period should be five years, to be reasonable and appropriate. The Public Staff, in its 51/49 "equitable sharing" proposal, suggests a period of 25 years (with no return), but its suggestion is tied to (indeed, mathematically required by) the sharing arrangement. As discussed more fully above, the Commission determines that the Public Staff's sharing proposal is from the Commission's perspective arbitrary and unfairly punitive and therefore unacceptable. Thus, a 25-year, no return amortization period is not approved. The five-year period suggested by the Company is identical to the period over which the Commission approved in the 2018 DEP Rate Case, as well as the period over which Dominion North Carolina Power's already-incurred coal ash basin closure costs were amortized in the 2016 DNCP Rate Case (Docket No. E-22, Sub 532). Further, inasmuch as the Company appropriately applied ARO accounting and this Commission's deferral orders issued in Docket No. E-7, Sub 723 to these costs, the Company is eligible to earn a return.

In summary, with the exception noted below, DEC has shown by the greater weight of the evidence that its coal ash basin closure costs actually incurred over the period from January 1, 2015 through December 31, 2017 are (a) known and measurable, (b) reasonable and prudent, and (c) where capital in nature used and useful, and, as such, those costs are recoverable in rates. DEC has further shown that its proposal that these costs be amortized over five years, with a modified return on the unamortized balance, is reasonable. The Commission encourages the selection of minority and women-owned businesses, where appropriate, when contracting for future services associated with compliance with CAMA and the CCR Rule.

8. The Commission's Cost of Service Penalty

The costs DEC has incurred through the end of the test year as adjusted in coal ash remediation tasks have been substantial, and the Company will continue on an annual basis to incur a substantial level of costs through approximately 2028. The vast majority of these costs would have been incurred irrespective of management inefficiency in order to comply with EPA CCR requirements. When DEC initially constructed coal ash impoundments and transported CCRs to them many decades ago, it did so in accord with the prevailing industry practices at the time, especially in this part of the country. In part and over time this was in response to environmental regulations requiring the removal of pollutants such as CCRs from the coal plant smokestacks to reduce air pollution.

Over time, the EPA and other environmental regulators have scrutinized the impact of CCRs in unlined repositories on surface and ground water and have assessed the extent to which harmful constituents in CCRs exceed those naturally occurring in the environment and their impact on human health. One long-lasting debate before EPA addressed the extent to which CCRs should be classified as hazardous waste under RCRA, a debate only recently resolved. Had EPA classified CCRs as a hazardous waste, economic reuse in all likelihood would have become an impossibility.

Another area of scrutiny has been the appropriate need for and method of remediation with respect to closing and potentially moving CCRs from unlined impoundments.

Many of the criticisms of DEC's CCR remediation practices raised in this case, before the federal district court in the criminal proceeding and before other courts and administrative agencies, address issues such as seeps from impoundment dikes, improper maintenance of dikes, lax reporting, exceedances and NPDES violations with respect to surface water discharges. The primary and ultimate remediation however is dewatering and excavation of and transportation from existing unlined impoundments and construction of new lined impoundments or, for older discontinued impoundments that qualify, caps preventing rainwater intrusion. This is where the vast majority of the billions of dollars of CCR remediation costs must be spent. This ultimate remediation step is necessary to prevent most of the leachate from infiltrating groundwater from the bottom of unlined basins, but would have been required irrespective of the harms that constitute other alleged mismanagement. In addition, this remediation process cures other less pervasive environmental and health threats.

Intervenors fault DEC for failure to undertake this remediation process years earlier before being required to do so. The evidence shows that DEC undertook steps toward CCR remediation and incurred costs in anticipation of impending closure but hesitated to spend substantial sums until the requirements became clearer. Had DEC acted in compliance with assertions that it act more aggressively sooner, it would have incurred costs its consumers would have been responsible for then. So from a ratemaking perspective, this Commission's concern, the question of when the remediation should have taken place, now or in the future or twenty years ago, is not determinative of whether the costs of the remediation should be recovered through rates and to what extent. Intervenors are unable to show when DEC should have acted differently in the past or what the increased costs would have been then. The Commission rejects efforts from any source to advance theories in support of discrete disallowances that parties before the Commission have not seen and have therefore been denied any opportunity to analyze and respond. The Commission must depend on parties before it, particularly the Pubic Staff, with the statutory responsibility to audit and respond to general rate case filings to advance theories for cost recovery.

Indeed, whenever undertaken, the costs would have been site specific, and establishing a past cost in this case would be a near impossibility. As DEC would have been required to undertake the remediation at issue in 2015 through 2017, irrespective of other improper actions of which it has been accused and for which it pled guilty to and was sentenced for in the criminal proceeding, any disallowance in this case must be made within the context of these facts. Had DEC acted irresponsibly in neglecting seeps earlier, the remedy would have been pumping the water from the seeps back into the basin, for example. Costs of this remediation would have been negligible in comparison to removing ash or cap-in-place.

DEC in the past contemplated a future requirement to close unlined impoundments. While it was reasonable and appropriate to anticipate and plan for what EPA's ultimate decisions would be, the Commission determines not to penalize DEC through denial of cost recovery for its decision to wait until EPA's CCR determinations in this area were finalized. Had DEC acted prematurely in anticipation of regulations under consideration but not yet implemented, with the expenditure of substantial sums in the process, and with the ultimate EPA decisions differing from those anticipated, DEC risked unjustified expenditures. In 2015, the EPA announced the Clean Power Plan. Had electric utilities incurred costs prematurely to comply, these costs could have been called into question when the U.S. Supreme Court stayed the Clean Power Plan. Even today efforts to soften the impact of the EPA CCR Rule are under consideration by the current administration. If effectuated, anticipated cost recovery may change in the future.

A significant example of the ambiguity and uncertainty DEC faced in the management of CCR impoundments is illustrated by reference to a November 1, 2004 Long Term Ash Strategy Study Phase Report addressing 1983 and 1984 CCR repositories at DEP's Sutton coal fired plant in New Hanover County referred to in the 2018 DEP order. The 1983 impoundment was unlined and had reached capacity prior to the 2004 report. The 1984 impoundment was lined and was rapidly approaching capacity, and the report identified and classified alternatives for CCR use or disposal to prevent shutdown of the Sutton plant. In the "Problem Description" section of the report, the authoring engineer listed issues either directly or indirectly related to a contribution to the overall ash strategy for the Sutton plant. The issues were described as secondary and not a dictating factor in the solution of the best alternative but as a look at overall environmental structure and stewardship. The first issue addressed the 1983 unlined impoundment that for the most part had ceased to receive CCRs.

> <u>1983 Pond is Unlined</u>
>
> The first issue is that the 1983 ash pond was constructed during a period when it was not required to provide a non-permeable liner, and was constructed with the native sandy soils.[76] This pond has been functionally full since 1983, but is still permitted[77], and is occasionally used when there are issues requiring the 1984 ash pond to be temporarily dry. The current environmental atmosphere is that these ponds will eventually have to [sic] emptied and placed in a lined containment to eliminate the leaching of the ash products into the groundwater system. This is an issue that is not currently being pressed, but it is anticipated that with the tighter environmental conditions it will soon become an emergent issue. This issue is aggravated by the fact that a test monitoring well located 300' from [sic] edge of the 1983 ash pond has shown high levels of arsenic during the past two quarterly tests. This may or may not be related to the unlined ash pond. A recent study by an independent firm indicated this concern may be less than originally thought. It could be mitigated by adding monitoring wells to the NPDES permit, but could still pose an issue in the future.[78] There is also a county well water source approximately 1200' from the test well that is monitored by the county.
>
> Elsewhere in the report under the "Do Nothing" alternative, the author stated:
> It is assumed that the North Carolina Division of Water Quality (NCDWQ) will require the 1983 ash pond to be emptied and lined to comply with current ash pond regulations. For the purpose of this study it is estimated that there is a 5% chance annually of the ash pond required to be relined

[76] The reference to “native sandy soils” is significant. Its characterization for absorption of leachates is greater than for the clay soils of the Piedmont at issue with respect to the DEC impoundments in this case.

[77] The 1983 impoundment operated pursuant to a DEQ permit. Obviously, at the date of the report, DEQ was not requiring closure or dewatering and removal of the CCRs. This would not occur until passage of the CCR Rule and CAMA years later.

[78] This recitation is consistent with the comprehensive testimony of witness Wells in this case that with respect to the types of contaminants at issue from CCR impoundments, they exist in naturally occurring quantities in the soil. Monitoring wells showing exceedances above standards are not dispositive without measurement of naturally occurring constituents.

starting 2007, and that in 2013 there will be a 10% chance annually thereafter until 2019.

In 2018, it is less than clear as to what the author refers to as the "current environmental atmosphere" or "current ash pond regulations." The author of the report does not elaborate or explain. Were the Commission to attempt to read the author's mind, this would be mere speculation. To the extent DEQ was enforcing them, DEQ was not requiring DEC to take additional steps to comply. As the report states, the 1983 impoundment was operating pursuant to a DEQ permit, and DEQ had not required closure. The author repeatedly uses the word "assumes" and "anticipated" to predict the environmental regulators' future intent. The author's speculation as to if and when unlined impoundments might have to be dewatered and excavated was off the mark. With respect to the 1983 Sutton unlined impoundment, that impoundment will never be relined. If it had been relined as the author suggests, the Company would have been required to move the CCR's twice, once to some new location, then back to the newly relined 1983 repository. Such is not the case for compliance with EPA CCR rules and CAMA where the CCR's were moved only once -- deposited in a new, lined landfill.[79]

The EPA's CCR rule was passed in 2015, and the NC CAMA was passed in 2014 with deadlines a number of years beyond that. DEC did not choose the alternative recommendation in the report, creation of an industrial park, nor did it excavate the unlined 1983 impoundment in response to the report. The report contains no recommendation to excavate the 1983 impoundment solely for environmental remediation. The Commission is unable today to say how in the past the 1983 impoundment would have been excavated and how the excavated CCRs would be placed in a lined impoundment, what the cost would have been and what cost recovery treatment would have been appropriate. Indeed, the 1983 impoundment today is being excavated pursuant to express EPA and DEQ guidelines, and the parties to the DEP case vigorously contest how compliance with these requirements should be accomplished and what the cost should be.

The purpose of the report was to determine the best course based upon the fact that the 1984 lined ash pond was reaching capacity and would be non-operational by June 2006. It is important to note that the author was indicating that the 1984 ash pond would be non-operational under the NPDES permit due to capacity constraints as opposed to environmental concerns.

Intervenors are advocating substantial disallowances in this case for expenditures DEC incurred to meet CAMA deadlines, such as at Dan River, Riverbend, or Buck, before all of the regulatory requirements had been finalized. A substantial area of contention is

[79] Intervenors are highly critical of DEC for failure to take action in response to consultants, in-house investigative teams and outside research entities such as EPRI before 2015. However, quite inconsistently, when it comes to criticizing DEC's actions after 2015, they assert that DEC was remiss in not stopping short of what SCDHEC wished for remediation of W.S. Lee and the consultant for the selenium treatment at Riverbend. They contend DEC spent too much in complying with these required or suggested remediation steps.

exceedances and environmental violations addressing harmful constituents in coal ash even though determinations with respect to naturally occurring levels of background concentrations of these constituents have not been established. Rules for regulating seeps from dikes are yet to be finalized. As testified to by witness Wells, with respect to covered engineered seeps, DEQ and DEC have been in long-standing negotiations as to whether seeps are a violation of the law and since 2014 whether seeps should be covered by the NPDES permit. Even as DEC continues to remediate, state regulatory agencies must review and approve the process and may impose additional restrictions, limitations and requirements. Even subsequent to EPA CCR rules and CAMA, the General Assembly enacted the Mountain Energy Act of 2015, changing the requirements for the Asheville plant remediation for DEP. Closure options for each of the CCR impoundments are site specific. Even now, Intervenors criticize the selection of repositories for beneficiation. Intervenors contend DEC spent too much to comply with CAMA. As discussed below, others advocate that this Commission supersede the authority of environmental regulators and require excavation of all DEC's impoundments and prohibit cap-in-place and spend more than DEC contemplates irrespective of what DEQ may require. The Commission is unable to recreate the past and place a price tag on remediation costs that might have been incurred in anticipation of environmental requirements.

Intervenors maintain that DEC should have addressed CCR remediation in years prior to EPA's CCR regulations and CAMA when the industry began to grow concerned over potential CCR environmental degradation. Under this theory, remediation costs would have been lower then and as a consequence CCR remediation costs DEC seeks for recovery beginning in 2015 are excessive and should be disallowed in whole or in part.

The most significant shortcoming in this theory is that no attempt has been made by any party to this case to demonstrate what the costs would have been in earlier years that theoretically would be so much lower as to make the 2015 and subsequent CCR remediation costs unnecessary or excessive. To the extent efforts are made in this case after the record has closed, as was the case in the DEP case, DEC has had no opportunity to respond and any such effort is unfair and inappropriate.

Before EPA CCR rules and CAMA, DEC's impoundments were operated under permits authorized and overseen by DEQ or its predecessor, clients of the AGO. DEQ suggested no requirements that DEQ dewater the impoundments, remove the CCRs and transport them to lined landfills or install caps in place. No requirements existed for DEC to follow. Had DEC undertaken impoundment closure, DEQ would have been required to oversee the process, but of what that oversight would have consisted is unknowable today.

DEC has incurred costs beginning in 2015 and thereafter pursuant to elaborate EPA and CAMA requirements under close scrutiny and oversight from DEQ. Parties to this case hotly contest and dispute the steps DEC has taken to comply and assert that DEC's expenditures have been unreasonable.

In an effort to comply with CAMA, DEC identified Buck as a beneficiation site. Public Staff witness Moore argues DEC should have chosen instead Weatherspoon and that DEC therefore spent $10,612,592 too much between January 1, 2015 and November 30, 2017.

In order to comply with CAMA, DEC constructed an onsite landfill of Dan River. Public Staff witness Moore argues that DEC selected the wrong site, the former footprint of the Ash Fill 1, and should not have increased the costs to transport CCR materials offsite. He contends that DEC spent $59,320,890 too much.

In order to comply with CAMA, DEC transported CCRs from the Riverbend Ash Stack to the R&B landfill in Homer, Georgia and to the Brickhaven facility. Public Staff witness Moore contends that the material should have been disposed of at the Marshall plant and DEC spent $489,600 too much.

In order to comply with SCDHEC requirements, DEC attempted to close the regulated ash basin of W.S. Lee and mitigate risks of the unregulated inactive ash basin and fill area. Public Staff witness Garrett disagreed with DEC's decision to immediately begin excavation and transportation from these basins and transport CCRs to the R&B landfill in Homer, Georgia. Witness Garrett testified that DEC spent $27,275,192 too much.

Public Staff witnesses contend that DEC spent $97,698,274 too much to comply with EPA and CAMA. Even with access to steps DEC took and to the compilation of costs DEC incurred, these witnesses encountered difficulty understanding what DEC did. Witness Moore calculated the cost for excavating, transporting and disposing of Ash Stack I at the Dan River off-site to be $83,531,985. This was $3.8 million too high because this amount should have been attributable to excavation and transportation of ash from the Primary Ash Basin. The cost to build the alternative landfill location when accounting for the need to address asbestos and relocate the warehouse building at Dan River increases witness Moore's cost determination by $10,790,900. Witness Moore originally included costs of parcels at Cliffside even though DEC had not requested recovery of those costs. Witness Moore assumed DEC began transport of CCRs from Riverbend to the R&B Landfill beginning May 2015 and continuing to February 2016. However, the DEC contract with Waste Management was for 17 weeks through September 18, 2015.

Witness Moore criticizes DEC for spending too much at Buck, Riverbend, and Dan River to comply with CAMA requirements. Witness Junis criticizes DEC for spending too much at Belews Creek and Riverbend for remediation not required by CAMA for selenium removal. Witness Quarles criticizes DEC for spending too little at Allen and Marshall to remediate by not removing the coal ash from the unlined basins there in disregard of what DEQ may ultimately require for compliance with CAMA. The Commission deems the various Intervenor theories for remediation cost disallowance "all over the map" and deficiently inconsistent.

With so much disagreement over what DEC should have done or is doing to comply with EPA requirements and CAMA, the Commission determines that insurmountable obstacles exist to quantify the alleged offsets that are a fundamental element to Intervenors' disallowance theory. The Public Staff, the agency required by statute to audit rate requests and recommend adjustments, candidly testified that it does not base its recommended equitable sharing recommendations on past DEC imprudence. That agency was unwilling to attempt to speculate what DEC should have done in the past, when it should have acted and, most significantly, what the costs would have been. No other party has undertaken such effort. Without any evidence sponsored by any witness quantifying what DEC should have spent in the past, the Commission has no basis for disallowing 2015-2017 DEC remediation costs in support of a theory that DEC should have done more prior to 2015.

The Commission would be required to anticipate the difficulty in complying with local ordinances like the ordinance DEC confronted from the City of Danville. The Commission would be required to anticipate the level of community opposition such as that experienced at Riverbend. The Commission would be required to anticipate what, if any, issues the legislature or DEQ might have imposed for beneficiation. The Commission would be required to anticipate the reaction of state or local representatives to DEC’s decision to excavate or cap-in-place repositories within their legislative districts. The Commission concludes such tasks are unwarranted.

Intervenor theory on groundwater exceedances is that DEC violates 2L standards whenever monitoring wells show exceedance of standards or where DEC has not installed monitoring wells in addition to those required by DEQ to disprove the existence of exceedances. Some of the exceedances were from measurements taken within the CCR impoundments. The Commission cannot accept this theory. The fallacy of the theory rests on the fact that the undisputed evidence is that all of the constituent elements measured against the standards, including iron, manganese and pH, constituents harmful neither to the environment nor human health, occur naturally in the North Carolina soils irrespective of the proximity of coal ash impoundments. The evidence shows that DEQ by its actions or inactions does not agree that the existence of exceedances without evidence that they are caused by coal ash contamination pose a risk to the environment or human health so as to require immediate remediation. DEQ has established a low priority to DEC's request to add 2L limits to NPDES permits. Although the Commission is not an environmental regulator, it must agree with DEC and DEQ that failure to take the costly actions required to comport with this Intervenor theory falls well short of mismanagement so as to justify some unquantified disallowance of 2015-2017 costs of dewatering and removal of CCRs from unlined pits or construct caps, which will cure exceedances caused by CCR groundwater contamination, if any.

This Commission’s responsibility is cost recovery. Environmental regulators must oversee protection of the environment and public health. The Commission’s responsibility is to determine whether coal ash remediation costs as required by environmental regulators should be recoverable through rates.

Another factor the Commission must address is the imposition of requirements of CAMA in addition to those of EPA. The evidence in this case is that the level of transportation and beneficiation costs being contested arises from more aggressive CAMA deadlines and uncertainty over the timing of the granting of regulatory permits for replacement impoundments. Except as addressed generically elsewhere, the Commission is reluctant to second-guess specific DEC decisions on its attempts to comply with these requirements in a 20/20 hindsight fashion. Likewise, the Commission is reluctant, except in limited fashion, to penalize DEC for good faith efforts to comply with state statutes irrespective of the factors motivating the General Assembly to impose them.

In his testimony, AGO witness Wittliff asserts that DEC's mismanagement caused CAMA and that costs DEC incurred to comply with CAMA in excess of those to comply with EPA CCR requirements should be disallowed. Witness Wittliff makes no effort to quantify the disallowance he proposes under this theory. In contradiction of its own witness, the AGO in its post-hearing brief argues that all of DEC's 205-2017 CCR remediation costs should be disallowed -- again without showing what DEC's costs should have been before 2015 under the AGO's theory. The AGO insists it is up to DEC to make these calculations for it.

Aside from the unsubstantiated theoretical underpinnings of the Wittliff argument, it is not possible to segregate CAMA 2015-2017 costs from EPA CCR costs. Indeed, a major prudency disallowance advocated by the Public Staff addresses 2015-2017 remediation costs at DEC's W.S. Lee plant in South Carolina. DEC was required to meet deadlines beyond those imposed by the EPA but not as a result of CAMA, which did not apply outside of North Carolina.

Conversely, the Commission is unable to find DEC faultless in the dilemma it has faced. Much testimony addresses the issue of whether DEC’s mismanagement of CCRs “caused” the General Assembly to enact CAMA. DEC argues that other nearby states enacted CCR remediation statutes in addition to EPA’s CCR rules, and that the Dan River spill affected the timing but not the substance of CAMA’s requirements. The Commission is unable to conclude that DEC mismanagement is the primary cause of CAMA. Just as a preamble never accepted cannot legally justify legislative intent, neither can the absence from earlier versions of CAMA that would have addressed cost recovery. Nevertheless, the provisions of CAMA directly address remediation of DEC CCR repositories and impose accelerated deadlines with respect to them. The Commission therefore is unable to conclude that DEC mismanagement to which it admitted in the federal criminal court proceeding was not at least a contributing factor. Even DEC witness Wright’s testimony suggests as much. While DEC presents persuasive evidence that its alleged mismanagement has not been supported and was not the cause of CAMA, this evidence is difficult to reconcile with its admissions and guilty pleas before the federal district court in the criminal proceeding. DEC represented that it mismanaged its CCR activities.

The Commission’s conclusions with respect to the impact of DEC’s mismanagement as a contributing factor to the enactment of CAMA are significant in two ways. First, the Commission determines that this conclusion adds support to the Commission's assessment of a management penalty in the form of cost disallowance arising primarily from the Company's admissions of mismanagement in the federal criminal case. Secondly, it supports the Commission's determination to reject more discrete disallowances such as those addressed by the Public Staff with respect to Buck, Riverbend and Dan River transportation costs. The Commission deems these costs traceable to CAMA timelines, implemented in part in response to DEC's CCR management practice, but is unpersuaded that the quantification of the costs is accurate or that the severity of the proposed disallowances is justified. Consequently, the Commission takes the incurrence of these costs into account in establishing the amount of its management penalty.

DEC admits to pervasive, system-wide shortcomings such as improper communication among those responsible for oversight of coal ash management. As stated above, while the Commission cannot state that CAMA would not have been passed or that its requirements other than accelerated deadlines would have been less onerous but for DEC's mismanagement of its CCR activities, neither can it state that DEC activities were without impact on the CAMA provisions that have resulted in increased costs that are at issue in this case. More fundamentally, in its admissions and pleas of guilty before the federal district court, DEC has outlined acts of criminal negligence through management misfeasance. In so doing, the Commission determines that, irrespective of CAMA, DEC has placed its consumers at risk of inadequate or unreasonably expensive service.

The Commission must regulate DEC pursuant to the requirements of Chapter 62 to see that compatibility with environmental well-being is maintained. N.C. Gen. Stat. § 62-2(a)(5). Service is to be provided on a well-planned and coordinated basis that is consistent with the level of energy needed for the protection of public health and safety for the promotion of the general welfare as expressed in the state energy policy, N.C. Gen. Stat. § 62-2(a)(6). All companies are prevented from violating environmental statutes. N.C. Gen. Stat. § 143-215.1. DEC is required to maintain safe and reliable service. As an electric utility, safety usually means safe electric service. In the context of this case, the Commission also determines that it means assuring safe operation of its coal-burning facilities so as not to render the environment unsafe. Declining to acquire and install a relatively inexpensive camera in a decades-old storm water drainage pipe over which the large coal ash impoundment is constructed when engineers repeatedly recommend such installation does not comply with a duty to provide safe service.

Fortunately, Dan River was a plant where coal-fired generation had been discontinued at the time of the 2014 spill. Risers in disrepair, inadequate oversight of impoundment dikes and seeps have not resulted in catastrophic failures causing plants to be taken offline or service disruptions, but DEC's irresponsible management of its impoundments over a discrete period of time placed its customers at risk of inadequate service and has resulted in cost increases greater than those necessary to adequately maintain and operate its facilities.

Consequently, having pled guilty to management criminal negligence, DEC cannot go without sanction in the form of cost of service disallowances. At the same time, to the extent the Dan River plant spill has contributed to the CCR remediation expense that otherwise would have been lower, the Company has borne responsibility for Dan River remediation costs without ratepayer support. The Company has been penalized by the federal district court. It cannot seek cost recovery of these monetary penalties or remediation assessments. Further, the mismanagement to which DEC pled guilty was only for a fraction of the time DEC operated the impoundments. No evidence was submitted that DEC's management was imprudent from the initial date of operation. The penalties imposed by this Commission take the form of denial of recovery of a return on historic remediation costs that reduce a portion of costs that ratepayers otherwise would have borne. The Commission deems double penalization inappropriate as an unwarranted penalty that has a tendency to unduly threaten the long-term overall wellbeing of the Company, a situation not in the best interest of its consumers.

A major difficulty the Commission confronts in this case is the identification and quantification of the appropriate CCR remediation adjustment to incurred costs. The record does not contain evidence appropriately quantifying the cost DEC incurred with respect to discrete remediation activities.[80] The Public Staff's witnesses' encountered difficulty in quantifying and supporting the costs for the alleged Cliffside, Riverbend and Dan River disallowances and other less specific ones motivates the Commission to resist imposition of discrete cost disallowances. The Commission deems disallowance of the totality of costs, as some parties advocate, unjustified. The Commission deems full recovery, as DEC advocates, unjustified. The Commission deems the Public Staff's 51/49 equitable sharing disallowance unfairly punitive and of questionable legal sustainability. The Commission deems requirements that more costs be imposed than DEQ might require without cost recovery unjustified. Moreover, the Commission deems it inadvisable to approve or suggest future disallowances with respect to CCR remediation expenditures as far away as 2028 and beyond. In sum, the Commission cannot agree with any of the parties in this case and must fashion and quantify a remedy different from any of those advocated before it.

The Commission operates under a legislative mandate that requires it to fix rates that will allow a utility "by sound management" to pay all of its reasonable operating costs, including maintenance, depreciation, and taxes, and earn a fair return on its investment. N.C. Gen. Stat. § 62-133(b)(4). State ex rel. Utils. Comm'n v. General Telephone Co.,

[80] As the Commission recited in its order in the DEP case, AGO witness Wittliff was asked whether he offered any opinion on what he thought the Company's appropriate amount of recovery under the CCR rule should be. He responded:

> ... I would explain that I'd love to have been able to come up with some extremely precise numbers and explain it all to you where it all made crystal clear sense and you could hang your hat on it and that's the number, we can pin that down. The problem is, is that this is, as we've already - - everyone seems to have observed, is it's an extremely complex case with a lot of moving parts, and it's not as easy to - - to make that sort of definitive statement. Tr. Vol. 15, pp. 77-78.

The same evidentiary shortcoming is present in the record in this case.

285 N.C. 671, 208 S.E.2d 681 (1974). If the Commission finds that a utility has not been soundly managed, it may penalize a utility by authorizing less than a "fair return." Id.[81] The Commission must quantify the penalty by making a finding of what return would have been allowed if there were sound management. Id. The North Carolina Supreme Court has stated that "[t]he size of the penalty is left to the judgment of the commission, but must be based upon substantial evidence, and the penalty must not result in a confiscatory rate of return." Id. General Telephone addressed a rate of return on rate base penalty for mismanagement resulting in inadequate service. In this case, DEC's mismanagement takes the form of admitted inadequate oversight of its CCR activities that placed service to its consumers at risk and, at least indirectly, increased costs. As the penalty is a defined monetary penalty rather than a percentage return penalty, the impact on cost of service would be the same if it had been a rate of return on rate base penalty.

Consequently, the Commission in the exercise of its judgment and discretion, determines that a management penalty in the approximate sum of $70 million is appropriate with respect to DEC CCR remediation expenses accounted for in the earlier established ARO with respect to costs incurred through the end of the test year as adjusted. This penalty is based on the totality of evidence contained in the record, as recited in detail above, and does not result in confiscation. Had the Commission not imposed this penalty, the ARO costs would have been amortized over five years with a full authorized return on the unamortized balance. As the Commission has addressed comprehensively above in this order, the Commission possesses the discretion to authorize a return on the unamortized balance. The unamortized balance is not a recurring test year operating expense. The annual amortization of the balance (return of not return on) is the amount that equals to operating expense pursuant to N.C. Gen. Stat. § 62-133(b)(3). The penalty will be imposed by reducing the resulting annual revenue requirement by $14 million (from the return on the unamortized balance on the capitalized costs) for each of the five years, resulting in an approximate $70 million management penalty. While this penalty differs in form from that in General Telephone, the Commission determines that conceptually General Telephone provides appropriate precedent. By imposing this management penalty, the Commission does not suggest that further penalty or disallowances with respect to past DEC actions or inactions will be imposed with respect to future CCR remediation expenses. The size of the penalty meets judicial requirements as it is quantified and is not confiscatory.

With respect to CCR remediation costs to be incurred during the period rates approved in this case will be in effect, the Commission determines that the "run rate" or the "ongoing compliance costs" mechanism advocated by DEC will not be approved. By requesting the creation of an ARO, in addition to the run rate, DEC concedes that treating CCR expenditures as a recurring test year expense is inadequate. Future annual costs, the evidence shows, are predicted to vary substantially from year to year. Instead, CCR

[81] See also State ex rel. Utils. Comm'n v. Morgan, 277 N.C. 255, 177 S.E.2d 405 (1970) (holding "that it is not reasonable to construe [the statute] to require the Commission to shut its eyes to 'poor' and 'substandard' service resulting from a company's willful, or negligent, failure to maintain its properties [] and it is obvious that consistently poor service, attributable to defective or inadequate or poorly designed equipment or construction justifies a subtraction …").

remediation costs incurred by DEC during the period rates approved in this case will be in effect shall be booked to an ARO that shall accrue carrying costs at the approved overall cost of capital approved in this case (the net of tax rate of return, net of associated accumulated deferred income taxes). The Commission will address the appropriate amortization period in DEC's next general rate case, and, unless future imprudence is established, will permit earning a full return on the unamortized balance. While this ratemaking treatment will, in limited fashion, diminish the quality of DEC's earnings, over time, assuming reasonable and prudent CCR management practices, it permits appropriate recovery. Prior to the next rate case, the Commission shall require that DEC provide a detailed accounting of its Cost of Removal Reserve for its steam assets and how the Company is utilizing this Cost of Removal Reserve.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 73

The evidence supporting this finding and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, the Stipulation, and the entire record in this proceeding.

Public Staff witness Maness stated that coal ash costs prudently incurred from 2015 through 2017 (i.e., costs not subject to Public Staff recommended disallowances apart from equitable sharing) should be allowed provisional cost recovery. Tr. Vol. 22, pp. 63-64. He explained that the reasonableness of some of those costs may depend on the outcome of legal proceedings or other legal determinations, as described by witness Junis. Id. Witness Junis testified that environmental lawsuits had not been resolved for several DEC plants. Tr. Vol. 26, p. 732.

Witness Wright argued against witness Maness' recommendation of provisional cost recovery. Witness Wright stated that provisional rates appeared to be retroactive ratemaking and the utility should not be subject to hindsight review. Tr. Vol. 12, errata pp. 156-39-40.

Provisional cost recovery is appropriate in certain circumstances. However, the Commission is not persuaded that there is good cause to order provisional cost recovery of DEC's CCR costs that are approved in this Order. The Commission has weighed the Public Staff's and other intervenors' concerns about the pending insurance lawsuits and pending determinations by DEQ, EPA, and certain courts, that will establish whether past actions of DEC amount to environmental violations against the uncertainty that is inherent in provisional rates. With regard to the insurance litigation, DEC has committed that insurance proceeds recovered by DEC will benefit ratepayers as an off-set to DEC's CCR costs. Further, the insurance proceeds are not known and measurable as of the end of the test year. Moreover, the Commission has included in this Order specific reporting requirements and other conditions with which DEC must comply regarding the insurance proceeds.

With respect to pending determinations by EPA and DEQ, the Commission is not inclined to delay its work in order to wait for these agencies to complete their work. As a result, on balance the Commission finds and concludes that it will not order that the CCR cost recovery in this docket is provisional.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 74-75

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, the Stipulation, and the entire record in this proceeding.

DEC has used a demand allocation factor to allocate its costs related to its compliance with state and federal environmental regulations regarding coal ash pond closures in this case. Tr. Vol. 19, p. 39. Additionally, the Company has identified specific CAMA-related costs and allocated these costs directly to North Carolina customers. Tr. Vol. 6, p. 314.

Public Staff witness Maness recommended applying a jurisdictional allocation of all coal ash expenditures by a comprehensive system factor. Tr. Vol. 22, pp. 66-68. He stated that his adjustment removed the distinction between costs DEC described as CAMA-only and the remainder of the coal ash costs. Id. at 66. He stated that for CAMA-only costs, DEC utilized North Carolina retail allocation factors that do not allocate any of the system level costs to South Carolina retail operations. Id. at 67. He opined that even though some of the costs incurred by DEC are being incurred pursuant to North Carolina law, it is fair and reasonable to allocate those costs to the entire system because the coal plants associated with the costs are being, or were, operated to serve the entire DEC system. Id. Public Staff witness Maness also stated that he used 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. Id. at 67-68. Witness Maness recommended that an energy allocator be used to determine the North Carolina retail portion of the coal ash costs because they 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. Id. at 68.

NCSEA witness Barnes also objected to DEC's classification of coal ash costs as demand related. He argued that this approach is contrary to cost causation principles because coal ash is a by-product of consumption of a fuel, and the volume of coal ash produced is associated with overall energy use, not demand during a single hour of the year. He recommended that all coal ash remediation costs approved for recovery be allocated using an energy allocator. Tr. Vol. 20, p. 62.

Additionally, CIGFUR III witness Phillips testified in support of the Company's proposed allocation of coal ash management costs on a demand basis, stating that such allocation "is appropriate and should be approved." Tr. Vol. 26, p. 258. CIGFUR III witness Phillips further testified that coal ash is not a fuel, but an environmental waste with no energy potential. Id. at 271. Witness Phillips also stated that compliance costs associated with coal ash remediation did not exist at the time the coal was burned, but arose more recently. Id. Therefore, remediation costs should not be allocated on a kilowatt-hour basis. Id. Further, the investment associated with coal ash ponds is typically included in generation plant accounts and should be allocated on the same basis and DEC allocates generation plant based on demand. Id.

In her rebuttal testimony, DEC witness McManeus opposed witnesses Maness' recommendation that the costs DEC identified as "CAMA only" be allocated to all jurisdictions, instead of directly assigning these costs to North Carolina. Tr. Vol. 6, p. 313. Witness McManeus explained that while she generally agrees that the costs of a system should be borne by all of the users of the system, the Company has identified very specific cost categories that should be treated as an exception to this general rule due to their nature as being unique to North Carolina. Id. These cost categories include groundwater wells used specifically for CAMA purposes and permanent water supplies provided to North Carolina customers pursuant to CAMA. Tr. Vol. 14, p. 120. Witness McManeus explained that this allocation is consistent with prior Commission decisions related to the Company's costs of complying with other North Carolina laws including REPS and the North Carolina Clean Smokestacks rule. Tr. Vol. 6, pp. 313-14. Because the Commission has allowed the Company to recover 100% of its costs associated with complying with those North Carolina laws, the Company believes it is also appropriate that CAMA-specific costs be directly assigned to North Carolina customers. Id. at 314.

Additionally, Company witness Hager responded to witnesses Maness' and Barnes' recommendation to classify coal ash costs as demand related. Witness Hager explained that the costs in question are associated with compliance with federal and state environmental requirements related to closing coal ash ponds. Tr. Vol. 19, p. 39. Residual end of life costs typically and logically follow the cost of the plant, which is allocated based on demand. Id. This is supported by the fact that end of life costs (removal costs) and salvage values are factored into depreciation rates, and depreciation expenses are allocated based on demand. Id. Witness Hager also noted that it is also consistent with end-of-life nuclear fuel costs in nuclear decommissioning costs which are allocated based on demand. Id. at 39-40.

The Commission finds and concludes, with respect to the above-stated adjustments, that it is appropriate to (1) allocate the costs DEC 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; and (2) allocate all coal ash expenditures by the energy allocation factor, rather than the demand-related production plant allocation factor. Regarding the jurisdictional allocation, the Company had directly assigned costs for certain groundwater wells and permanent water supplies to North Carolina on the grounds that such costs were mandated by CAMA and were unique to North Carolina. Tr. Vol. 6, pp. 259, 313-14; Tr. Vol. 14, p. 134. In contrast, witness Maness argued the coal plants had served the entire North Carolina and South Carolina system of DEC, so the costs should be allocated across both jurisdictions. Tr. Vol. 22, pp. 66-67. Regarding the allocation factor, the Company recommended the demand-related factor (Tr. Vol. 6 p. 314; Tr. Vol. 19, pp 39-40), whereas the Public Staff argued for the energy-related factor because the amount of coal ash is related to the amount of energy produced. Tr. Vol. 22, pp. 67-68. The Commission agrees with Public Staff witness Maness that the amount of coal ash correlates with the amount of energy produced from coal, and that the entire DEC system benefited from that energy. Accordingly, and consistent with the Commission's February 23, 2018, Order in Docket No. E-2, Sub 1142, the Commission finds and concludes that the deferred coal ash costs should be allocated across the entire DEC system, and should be allocated on the energy-related factor.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 76-78

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

On February 26, 2018, the AGO filed a Stipulation as to Admission of Evidence. The AGO and DEC stipulated that the testimony given by Company witness David Fountain regarding insurance coverage in Docket No. E-2, Sub 1142 (DEP Rate Case), along with the associated exhibits, is appropriate to be admitted into evidence in the present case. The testimony was located in the DEP Rate Case in Volume 7 of the transcript in pages 368 through 505 and AGO Fountain Cross Examination Exhibits 1 through 8.

In its post hearing brief, the AGO requested that the Commission monitor the insurance litigation and contended that it would be appropriate for the Commission to make similar findings and conclusions regarding insurance that it made recently in the DEP Rate Order.

The Commission concludes that DEC should be required to place all insurance proceeds received or recovered by DEC in the Insurance Case in a regulatory liability account and hold such proceeds until the Commission enters an order directing DEC as to the appropriate disbursement of the proceeds. In addition, the regulatory liability account shall accrue a carrying charge at the overall rate of return authorized for DEC in this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 79

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

With regard to DEC's CCR costs from 2018 forward, DEC witness McManeus testified that DEC is requesting to establish a regulatory asset/liability account and defer to this account the portion in annual rates that is more than DEC's actual costs, or the amount in annual rates that is less than DEC's actual costs. In essence, the asset/liability account would be a tool used to true-up the difference in DEC's next general rate case.

The Commission agrees with DEC's recommended approach, not only for CCR costs, but also for all cost deferral accounts. A deferred cost is not the same as the other cost of service expenses recovered in the Company's non-fuel base rates. A deferred cost is an exception to the general principle that the Company's current cost of service expenses should be recovered as part of the Company's current revenues. When the Commission approves a typical cost of service, such as salaries and depreciation expense, there is a reasonable expectation that the expense will continue at essentially the same level until the Company's next general rate case, at which time it will be reset. On the other hand, when the Commission approves a deferred cost the Commission identifies a specific amount that has already been incurred by the Company, or, in the case of CCR costs, is estimated to be incurred by the Company. In addition, the Commission sets the recovery of the amount over a specific period of time. Further, the Company is directed to record the recovery of the specific amount in a regulatory asset account, rather than a general revenue account. If DEC continues to recover that deferred cost for a longer period of time than the amortization period approved by the Commission that does not mean that DEC is then entitled to convert those deferred costs into general revenue and record them in its general revenue accounts. Rather, the Company should continue to record all amounts recovered as deferred costs in the specific regulatory asset account established for those deferred costs until the Company's next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 80-82

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

The Company presented Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues reflecting DEC's revised requested increase incorporating the provisions of the Stipulation, the Company's position on the unresolved issues and the impact of the EDIT decrement riders. Per those exhibits, the resulting proposed revenue requirement increase of the Company is $372,527,000. Boswell Corrected Third Supplemental and Stipulation Exhibit 1, Schedule 1 shows the Public Staff's revised recommended incorporating the provisions of the Stipulation, the impact of the EDIT decrement riders and its adjustments reflecting the Public Staff's position on the unresolved issues. The resulting proposed revenue requirement adjustment by the Public Staff is ($385,697,000).

As discussed in the body of this Order, the Commission approves the Stipulation in its entirety and makes its individual rulings on the unresolved issues as discussed. Due to the intricate and complex nature of some of the issues, the Commission requests that DEC recalculate the required annual revenue requirement as consistent with all of the Commission's findings and rulings herein within 10 days of the issuance of this Order. The Commission further orders that DEC work with the Public Staff to verify the accuracy of the recalculations. Once the Commission receives this filing, the Commission will work promptly to verify the calculations and will issue an Order with final revenue requirement numbers.

In addition, the Commission requests that DEC and the Public Staff provide the Commission with the demand and energy allocation factors that they, respectively, deem appropriate for allocating the CAMA costs to the North Carolina retail jurisdiction.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 83

The evidence supporting this finding of fact and conclusions is contained in the Company's verified Application, the testimony and exhibits of all the witnesses, the Stipulation, and the entire record in this proceeding.

Pursuant to N.C. Gen. Stat. § 62-133(a), the Commission is required to set rates that are "fair both to the public utilities and to the consumer." In order to strike this balance between the utility and its customers, the Commission must consider, among other factors, (1) the utility's reasonable and prudent cost of property used and useful in providing adequate, safe and reliable service to ratepayers, and (2) a rate of return on the utility's rate base that is both fair to ratepayers and provides an opportunity for the utility through sound management to attract sufficient capital to maintain its financial strength. See N.C. Gen. Stat. § 62-133(b). DEC's continued operation as a safe, adequate, and reliable source of electric service for its customers is vitally important to DEC's individual customers, as well as to the communities and businesses served by DEC. DEC presented credible and substantial evidence of its need for increased capital investment to, among other things, maintain and increase the reliability of its system and comply with environmental requirements.

Based on all of the evidence, the Commission finds and concludes that the revenue requirement, rate design and the rates that will result from this Order strike the appropriate balance between the interests of DEC's customers in receiving safe, reliable and efficient electric service at the lowest possible rates, and the interests of DEC in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the Commission concludes that the revenue requirement and the rates that will result from that revenue requirement established as a result of this Order are just and reasonable under the requirements of N.C. Gen. Stat. § 62-30, et seq.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation filed by DEC and the Public Staff on February 28, 2018, is hereby approved in its entirety.

2. That the Lighting Settlement entered into by DEC and NCLM, Concord, Kings Mountain, and Durham, is hereby approved in its entirety.

3. That DEC shall recalculate and file the annual revenue requirement with the Commission within 10 days of the issuance of this Order, consistent with the findings and conclusions of this Order and the Stipulation. The Company shall work with the Public

Staff to verify the accuracy of the filing. DEC shall file schedules (North Carolina Retail Operations – Statement of Rate Base and Rate of Return, Statement of Operating Income, and Statement of Capitalization and Related Costs) summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determinations in this proceeding. In addition, DEC and the Public Staff shall provide the Commission with the demand and energy allocation factors that they, respectively, deem appropriate for allocating the CAMA costs to the North Carolina retail jurisdiction.

4. That DEC is hereby authorized to adjust its rates and charges in accordance with the Stipulation and findings in this Order effective for service rendered on and after the following day after the Commission issues an Order accepting the calculations required by Ordering Paragraph No. 3.

5. That the Commission shall issue an Order approving the final revenue requirement numbers once received from DEC and verified by the Public Staff as soon as practicable.

6. That the appropriate revenue requirement for the first four years shall be reduced by the annual State EDIT rider decrement of $60,102,000.

7. That it is appropriate to recognize a $211,512,000 per year reduction in DEC's revenue requirement to reflect the current 21% Federal corporate income tax rate in DEC's base rates.

8. That DEC's proposed $200 million per year credit metric mitigation measure is denied.

9. That DEC shall continue to maintain all EDIT related to the Tax Act in a regulatory liability account for three years or until its next general rate case, whichever is sooner, at which point it will be returned to DEC's customers with interest reflected at the overall weighted cost of capital approved in this case of 7.35%. If DEC has not filed an application for a general rate case proceeding by June 22, 2021, it shall file its proposal by that date to flow back to its ratepayers both the protected and the unprotected EDIT generated due to the Tax Act. The federal EDIT flowback proposal should include all workpapers that support the proposed calculations. The Public Staff is specifically requested to file comments on the proposal by no later than July 22, 2021. Other parties also may file comments on the proposal by no later than July 22, 2021.

10. That DEC's request to establish a rider to recover Power Forward costs is denied.

11. That DEC's request, as an alternative to a rider, to establish a regulatory asset for the deferral of Power Forward costs is denied.

12. That DEC is instructed to collaborate with the intervening parties, through the generic and DEC-specific Integrated Resource Planning and Smart Grid Technology

Plan docket, toward the goal of resolving some or all of the issues surrounding grid modernization and the most appropriate cost recovery mechanism for such costs.

13. That the Pilot Grid Rider Agreement and Stipulation is disapproved.

14. That the Company shall implement an increment rider, beginning on the effective date of rates in this proceeding, and expiring at the earlier of (a) May 31, 2020,[82] or (b) the last day of the month in which the Company's actual coal inventory levels return to a 35-day supply on a sustained basis, as defined in this Order, to allow the Company to recover the additional costs of carrying coal inventory in excess of a 35-day supply (priced at $73.23 per ton). The Company shall adjust the rider annually, concurrently with its DSM/EE, REPS, and fuel adjustment riders.

15. That on or before March 31, 2019, the Company, in consultation with the Public Staff, shall complete an analysis showing the appropriate coal inventory level given market and generation changes since the Company's rate case in Docket No. E-7, Sub 1026.

16. That the approved base fuel and fuel-related cost factors (excluding regulatory fee), by customer class, are as follows: 1.7828 cents per kWh for the Residential class, 1.9163 cents per kWh for the General Service/Lighting class, and 2.0207 cents per kWh for the Industrial class.

17. That the Company is hereby, authorized to establish a regulatory asset for deferral of post in-service costs for Lee CC, as described herein. These costs shall be amortized over a four-year period.

18. That DEC's request to cancel the Lee Nuclear Project is granted.

19. That DEC's request to recover its project development costs relating to the Lee Nuclear Project is granted, with the exception of costs relating to the Visitors Center and the 2018 AFUDC, as described herein.

20. That the balance of Lee Nuclear Project development costs, adjusted to remove land costs, shall be moved from CWIP Account 107 to regulatory asset Account 182.2 and amortized over a 12-year period, and that the Company shall not earn a return on the unamortized balance.

21. That the Public Staff's proposal that the Company be required to refund to customers $29 million per year relating to the Company's NDTF is hereby, denied.

22. That the depreciation rates proposed by DEC in this case, as modified by this order, are approved.

[82] The Company may request an extension of the May 31, 2020 date.

23. That the aspects of rate design agreed upon in the Stipulation are approved and shall be implemented.

24. That the Company shall increase the monthly BFC for the residential rate class (Schedules RS, RT, RE, ES and ESA) to $14.00. The BFC for other rate schedules shall remain unchanged.

25. That the Company is hereby authorized to establish a regulatory asset to defer and amortize expenses associated with the Customer Connect project. The regulatory asset account shall accrue AFUDC until the DEC Core Meter-to-Cash release (Releases 5-8) of the Customer Connect project goes into service or January 1, 2023, whichever is sooner. At that point, the costs will be amortized over 15 years.

26. That DEC shall file reports regarding the development, spending, and accomplishments of the Customer Connect project each year by February 15 for the next five years or until the Customer Connect project is fully implemented, whichever occurs later. Further, DEC and the Public Staff shall develop the reporting format for the annual Customer Connect project report and file the format with the Commission within 90 days of this Order.

27. That DEC shall prepare and file a lead-lag study in its next general rate case.

28. That DEC's request to recover its AMI costs of $90.9 million in this proceeding is hereby approved.

29. That within six months of the date of this Order, DEC shall file in this docket the details of proposed new time-of-use, peak pricing, and other dynamic rate structures that will, among other things, allow ratepayers in all customer classes to use the information provided by AMI to reduce their peak-time usage and to save energy.

30. That DEC's costs for AMR meters replaced by AMI shall be recovered over a 15-year period.

31. That the Company's proposal for a JRR, as modified by this Order, and the JRRR are hereby approved for a one-year pilot with an option to renew it for a second year if the Company provides evidence that the JRR is achieving its intended purpose.

32. That the JRR and JRRR revenues shall be reported to the Commission annually, if the JRR is in effect more than one year, and the JRRR shall be reviewed and will be subject to adjustment annually coincident with DEP's December fuel adjustment to match anticipated recovery revenues and true-up any past over-or under-recovery.

33. That due to the uncertain date of implementation, compliance tariffs shall be filed prior to implementation of the JRRR and customers shall be notified by bill insert or message upon implementation.

34. That with respect to the Company's vegetation management program, the Company shall eliminate the 13,467 miles of Existing Backlog, as described herein, within five years after the date rates go into effect in this proceeding.

35. That any accelerated amount of expenditures to eliminate the Existing Backlog shall not be used to increase the level of vegetation management expenses in future proceedings, but shall not prohibit the Company from seeking adjustments for vegetation management contractor increases.

36. That DEC shall provide a report annually to the Commission with the following information: (1) actual 5/7/9 and Existing Backlog miles maintained in the previous calendar year; (2) current level of Existing Backlog miles; (3) vegetation management maintenance dollars budgeted for the previous calendar year for 5/7/9 and Existing Backlog; and (4) vegetation management maintenance dollars expended in the previous calendar year for 5/7/9 and Existing Backlog.

37. That the proposed amendments to DEC's Service Regulations are hereby approved.

38. That the Public Staff shall facilitate discussions with the electric utilities to evaluate and document a basis for continued use of minimum system and to identify specific changes and recommendations as appropriate. If the Public Staff ultimately recommends an alternative approach to minimum system as a result of this review, then the support for that position should be clearly defined. The Public Staff shall submit a report on its findings and recommendations to the Commission no later than the end of the first quarter of 2019 in a new, generic electric utility docket to be established by the Chief Clerk for this purpose.

39. That DEC shall file annual cost of service studies based on Winter Coincident Peak as well as the SCP and SWPA methodologies. In its next general rate case, the Company shall prepare cost of service studies based on each of these methodologies.

40. That DEC's proposal to discontinue Residential Water Heating Service Controlled/Sub Metered Schedule is approved.

41. That DEC shall recover the actual coal ash basin closure costs DEC has incurred during the period from January 1, 2015, through December 31, 2017, in the amount of $545.7 million, to be adjusted based on the allocation factors to be provided by DEC and the Public Staff pursuant to Ordering Paragraph No. 3, and DEC is authorized to establish a regulatory asset as requested in the Company's petition in Docket No. E-7, Sub 1110. These costs shall be amortized over a five-year period, with a return on the unamortized balance and then reducing the resulting annual revenue requirement by $14 million for each of the five years.

42. That DEC shall not be allowed to recover on an ongoing basis $201.3 million in annual coal ash basin closure costs, subject to true-up in future rate cases. DEC is authorized to record its January 1, 2018 and future CCR costs in a deferred account until its next general rate case. This deferral account will accrue a return at the overall rate of return approved in this Order.

43. That within 10 days of the resolution by settlement, dismissal, judgment or otherwise of the litigation entitled Duke Energy Carolinas, LLC, et al. v. AG Insurance SA/NV, et al., Case No. 17 CVS 5594, Superior Court (Business Court), Mecklenburg County, North Carolina (Insurance Case), DEC shall file a report with the Commission explaining the result and stating the amount of insurance proceeds to be received or recovered by DEC. This reporting requirement shall apply even if the case is appealed to a higher court.

44. That DEC shall place all insurance proceeds received or recovered by DEC in the Insurance Case in a regulatory liability account and hold such proceeds until the Commission enters an order directing DEC regarding the appropriate disbursement of the proceeds. The regulatory liability account shall accrue a carrying charge at the overall rate of return authorized for DEC in this Order.

45. That if DEC receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company shall continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case.

46. That the Commission's approval in the Order for deferral accounting and other accounting procedures is without prejudice to the right of any party to take issue with the amount of or the accounting treatment accorded these costs in any future regulatory proceeding.

47. That within 30 days of this Order, but no later than ten business days prior to the effective date of the new rates, DEC shall file for Commission approval five copies of all rate schedules designed to comply with this Order, accompanied by calculations showing the revenues that will be produced by the rates for each schedule. This filing shall include a schedule comparing the revenue that was produced by the filed schedules during the test period with the revenue that will be produced under the proposed settlement schedules, and the schedule illustrating the rates of return by class based on the revenues produced by the rates for each schedule.

48. That DEC shall submit a proposed customer notice to the Commission for review and approval, and upon approval of the notice by the Commission, shall give appropriate notice of the approved rate adjustment by mailing the notice to each of its North Carolina retail customers during the billing cycle following the effective date of the new rates.

ISSUED BY ORDER OF THE COMMISSION.

This the 22nd day of June, 2018.

NORTH CAROLINA UTILITIES COMMISSION

Linnetta Threatt, Deputy Clerk

Commissioner ToNola D. Brown-Bland concurring in part and dissenting in part.

Commissioner Daniel G. Clodfelter concurring in part and dissenting in part.

Commissioner Charlotte A. Mitchell did not participate in this decision.

DOCKET NO. E-7, SUB 1146
DOCKET NO. E-7, SUB 819
DOCKET NO. E-7, SUB 1152
DOCKET NO. E-7, SUB 1110

Commissioner Daniel G. Clodfelter, concurring in part and dissenting in part:

As to a very large number of the myriad issues decided in the Commission's Order in these consolidated cases, I concur in the results reached by the majority. On four topics, however, I would reach different outcomes, and I write separately here to explain my dissent. To summarize my differences from the majority:

I. I would disallow recovery of $244,433,678[1] from the expenditures made by the Company during 2015, 2016, and 2017, related to closure of waste coal ash storage facilities at the Company's eight coal-fired generating plants and for permanent disposal of the waste ash from those facilities, on the grounds that these amounts, in some instances, represent expenditures that were imprudently incurred and, in other instances, represent amounts that the Company imprudently failed to recover in prior rates.

II. For all allowed costs incurred during the period 2015 through 2017, as to the closure of the waste ash storage units and disposal of the ash, I would allow deferral and recovery amortized over a period of five years, but without allowance of any rate of return on the unamortized balance. I would so decide on the grounds that, as to some of such costs, allowance of a rate of return is not authorized by law and, as to all of such costs, the record presented in this case does not and cannot support allowance of a return as a matter of Commission discretion.

III. I would not authorize any increase in the fixed monthly charge (the so-called "basic facilities charge" or "BFC") imposed on residential rate classes on the grounds that there is no evidence in the record to support any such increase.

IV. I would permit the Company to defer to a regulatory asset account its costs for deployment of AMI meters, without a carrying charge, on the grounds that the record as it now stands cannot support a finding that this investment is reasonable or prudent.

In the following sections, I discuss the evidence and rationale for these conclusions in more detail.

[1] This total, as with the other amounts discussed in this section, are systemwide numbers and do not represent the North Carolina retail allocation. The data presented by the Company on waste ash expenditures were all on a systemwide basis.

I. Cost Recovery for Permanent Closure of Waste Coal Ash Facilities

A. General Matters

I start with a truism – each case stands upon its own merit and its own facts. This case follows hard on the heels of the proceeding in Docket No. E-2, Sub 1142 (DEP Rate Case), the general rate case of the Company's affiliate, Duke Energy Progress, LLC (DEP), decided by Commission Order dated February 23, 2018 (DEP Rate Case Order). For issues centering on the storage and disposal of wastes[2] from the burning of coal to generate electricity, the two cases are intimately linked, both factually and legally, but the evidentiary presentation in the two cases was not identical. It is because of the differences that I begin my dissent in this case in the same manner as I began my dissent in the DEP Rate Case[3] with a brief commentary on the state of the evidentiary record.

The evidence presented in this case, and most especially the documentary record that speaks to historical industry practices and standards, and to the Company's own internal policies and practices relating to the management of coal ash wastes, is considerably better developed than it was in the DEP Rate Case. This is largely due to the efforts of the Public Staff and several of the intervenor parties, most especially the Attorney General's Office (AGO). In some instances the new or additional evidentiary materials are pertinent not only to adjudication of the Company's request in this case, but also speak directly to factual issues that were in play in the DEP Rate Case. Sometimes the additional evidence in this case presents issues not considered at all in the DEP Rate Case or opens lines of inquiry not identified in that case. Many documents are dated after the time the Company and DEP became affiliated entities, and they address plant decommissioning and ash basin closure plans, activities, and costs for DEP facilities as well as for the Company's plants. Since these documents were not introduced as part of the record in the DEP Rate Case, they could not form the basis for any of the findings of fact or conclusions of law in DEP Rate Case.

As noted, the differences between this case and the DEP Rate Case are largely manifested in the presentations by the Public Staff and by intervenors. On the other hand, the Company's evidentiary presentation in this case largely mirrored and followed DEP's approach in the DEP Rate Case, an approach I have found less than satisfactory in both cases.[4] The Company depends on the evidence of witnesses whose testimony is very often of questionable value, largely because they lacked pertinent knowledge or

[2] These are euphemistically called sometimes "coal combustion residuals," or "CCRs," for shorthand reference. Because I think this manner of speaking tends to obscure, rather than to clarify the topic, I will continue to call them "wastes," which is in fact what they are.

[3] DEP Rate Case Order at pp. 248-278.

[4] As an initial matter, it is worth a reminder that the Company alone has the burden of proving its case-in-chief when it elects to file an application requesting a rate increase through a general rate case. It is not required of, nor would it be appropriate for, the Commission, the Public Staff, or any other intervening parties to fill in the gaps of any lacking evidence which may be necessary to substantiate the Company's *prima facie* case.

experience of the matters about which they testified, and expressed opinions and conclusions for which they had insufficient foundation. With very limited exceptions, *all* of the evidence in the record for the time prior to 2014 concerning (1) industry standards and practices relative to the management of coal ash wastes, (2) the Company's history of management of coal ash wastes, and (3) the pertinent regulatory requirements relating to coal ash wastes exist in this record only in the form of documents and exhibits offered by the Public Staff or by various other intervenors, or in the form of late-filed exhibits filed by the Company in response to specific questions and requests for information made by members of the Commission, on the record, during the evidentiary hearing. The Company's primary witness on these matters, witness Kerin, only first assumed responsibility for the Company's response to coal ash issues in 2014, without any pertinent prior experience concerning the subject. Notwithstanding this, he testified: "I'm the witness on coal ash for the Company." Tr. Vol. 24, p. 167. Although he testified that he had reviewed various historical documents and Company records as part of his introduction to his new duties, on a number of occasions during the evidentiary hearing, he was confronted with significant historical Company or industry documentation which was altogether unfamiliar to him or which he could not recall well enough to discuss. See, e.g., Tr. Vol. 14, pp. 252-271; Tr. Vol. 15, pp. 12-121. His conclusory testimony that the Company had complied with all pertinent laws and regulations, and had conformed to industry standards prior to 2014, simply cannot be afforded any substantial weight.[5] Company witness Wells, whose experience dated from 2009, displayed a better knowledge of the historical documentary record, but his own experience was limited to environmental compliance matters and did not extend to ash basin design, construction, operation, maintenance, or management issues, or to planning and cost recovery for closure of ash surface impoundments. The Company provided no witness who could testify concerning the Company's budgeting for, accounting for, or recovery of costs

[5] The majority seeks to buttress witness Kerin's credibility concerning historical matters by referring to the peer group of regional utility companies which witness Kerin convened and participated in since having assumed his current role in 2014, and points to the knowledge he has gained from those peer companies about past practices concerning coal ash wastes. Under cross-examination, however, witness Kerin admitted that the principal purpose of his peer group was to discuss forward-looking issues relating to implementation of the EPA's CCR Rule and related post-CCR Rule regulations at the state level. He also acknowledged that in response to a discovery request submitted by the AGO, he had not been able to provide any significant substantive information he had learned from his peer group about historical coal ash management practices. See Tr. Vol. 15, pp. 70-75; Kerin Direct AGO Cross Ex. 9 (Ex. Vol. 16, Part 3, pp. 309-311).

Witness Kerin's knowledge of matters dating before 2014 was so deficient that at the close of cross-examination, counsel for the Attorney General moved to strike his testimony concerning industry standards and practices and the Company's own policies and practices concerning the management of coal was wastes prior to 2014. Tr. Vol. 15, pp. 76-78. The motion was denied as having been made untimely pursuant to Commission Rule 1-21(c). The motion was in fact timely made, being one which the cited rule recognizes as arising in the course of the hearing to which it relates and, therefore, exempt from the ten-day prior notice requirement. I suppose that in defense of the ruling it could be argued that the motion was actually a "dispositive" motion and therefore subject to the ten-day prior notice requirement, since excluding witness Kerin's testimony would have deprived the Company of its only witness supporting the Company's *prima facie* case on issues going to the prudence and reasonableness of the Company's management of coal ash wastes prior to 2014.

associated with the handling of coal ash wastes prior to 2014.[6] This is a matter that takes on some significance for reasons to be discussed later in Section I.C. of this dissenting opinion. Finally, Company witness Wright's testimony consisted very largely of inadmissible legal opinions concerning his interpretation of provisions of Chapter 62 of the North Carolina General Statutes, and his conclusions as to whether the legal standards therein were satisfied in this case.[7] E.g., State v. Weeks, 322 N.C. 152, 164-65, 367 S.E.2d 895, 903 (1988); State v. Ledford, 315 N.C. 599, 340 S.E.2d 309 (1986).

As already noted, the evidence presented by the Public Staff and several of the intervenors was considerably more detailed and informative in providing an understanding of the evolution of industry standards and practices relating to waste coal ash. But, as was the case in the DEP Rate Case, significant gaps opened when it came time to show how the Company's responses to those evolving standards and practices translated into excessive or avoidable costs for which recovery in this rate case should be disallowed. The presentations by most of the intervenors, and the responses and replies by the Company, centered very largely on subsidiary issues: whether exceedances of North Carolina's 2L groundwater protection standards[8] (2L Rules) are "violations of law" and thus are evidence of imprudence, whether the allowance or creation of unpermitted seeps from ash impoundments is evidence of imprudence or is instead part of the natural order of things, whether the continued use of unlined surface impoundments into the current decade was or was not imprudent, whether delays in instituting comprehensive and continuing groundwater monitoring programs at all plants was or was not imprudent, and so on. With the exception of the Public Staff the parties objecting to the Company's requested rate increase made less effort to connect these subsidiary issues to the ultimate question the Commission must decide, which I summarize as follows: did the Company mismanage its waste ash storage and disposal facilities, either generally over a period of years, or else in discrete instances, in ways that unreasonably caused it to incur costs today that it could have avoided, or that caused an unreasonable increase in the level of costs for tasks that it would have to undertake in any event? Put differently, how much, if at all, have the costs of closure of the waste coal ash facilities been increased by the Company's acts or omissions addressed in one or more of these subsidiary issues? Here, the evidence and arguments of the parties have, in my judgment, been less helpful to the Commission than I would have wished. In the

[6] As an example of this omission, I point to Fountain Direct AGO Cross Ex. 6, a document titled "Ash Basin Closure Update," dated January 13, 2014. Tr. Vol. 9, p. 100-103; Ex. Vol. 10, pp. 609-694. That document included information concerning the Company's accumulated reserves for decommissioning expenses of its coal-fired steam plants and contained some discussion about options for using these reserves to offset the costs of ash basin closures. Although his name appeared on the title page as one of the authors of the document, Company witness Fountain was unable to answer questions about this information. Later witnesses, including Company witness Doss, and the Company's third-party witnesses Spanos and Kopp, who testified concerning depreciation and decommissioning costs, were likewise unable to answer questions attempting to explore the information contained in this exhibit.

[7] See, e.g., Tr. Vol. 26, pp. 157-230.

[8] N.C. Gen. Stat. § 143-211 et seq.; 15 N.C.A.C. .02L .0101 et seq.

following discussion I have tried to undertake answering that question in a manner that is supported by the available evidence.

B. Specific Disallowances of Requested Cost Recovery

I address first the Public Staff's proposals for specific cost disallowances, which the Public Staff does attempt to link to discrete acts or omissions by the Company that are alleged to have been imprudent or unreasonable. With respect to most of those proposals, I concur in the results reached by the majority. While I disagree with the narrow reading of the Glendale Water[9] case that appears to be espoused by the majority, I agree that on the specific facts of this case, the Public Staff's proposed disallowance of legal expenses in the amount of $2,109,406 is not warranted under my own reading of Glendale Water. I leave my disagreement about interpretation of that case for another time when it may make a difference to the outcome. For the reasons set forth by the majority, I agree that (a) the Public Staff's proposed disallowance of groundwater extraction and treatment costs at Belews Creek, (b) the Public Staff's proposed disallowance of costs for equipment purchased to treat and remove selenium from waste ash at the Riverbend Plant, (c) the Public Staff's proposed disallowance of costs incurred for temporary and short-term transport of ash wastes from the Riverbend Plant for offsite disposal in Homer, Georgia, and (d) the Public Staff's proposed disallowance of costs arising from the selection of the Buck Steam Station as a beneficiation site under CAMA[10] should not be accepted, and these costs should instead be allowed as requested by the Company, subject to the general adjustment arising from matters discussed in Section I.C. hereafter.[11]

In the following Sections 1.B.(i)-(ii), I discuss my differences with the majority with respect to two items for which the Company seeks recovery of expenditures made in 2015, 2016, and 2017. In each case, I conclude that the greater weight of the evidence shows that the Company did not act in a reasonable and prudent manner. Instead, the Company elected to pursue higher cost closure activities when, based on what was known at that time, reasonable lower cost alternatives were still available. In addition, I find that these costs were incurred in direct consequence of the Company's admitted imprudence and mismanagement of its waste ash impoundments at Dan River Steam Station (Dan River Plant) and that, but for the release of waste ash into the Dan River in February, 2014, such costs could or would have been avoided.[12] Finally, in Section I.C.,

[9] State ex rel. Utilities Comm'n v. Public Staff, 317 N.C. 26, 343 S.E.2d 898 (1986).

[10] S.L. 2014-122.

[11] I also agree with the Commission's majority decision to disallow $1,606,185 for costs incurred to provide temporary bottled water supplies to customers, as far as it goes. However, I believe that decision should also have included the additional $1,862,898 spent by the Company through August, 2017, to provide *permanent* alternative drinking water supplies to customers in the vicinity of some of its coal-fired plants.

[12] For present purposes, I find that the Company's guilty plea to Counts One through Four (Dan River Plant) and Count One (Riverbend Plant) of the federal criminal indictment, supported by the Joint Factual Statement, sufficiently establishes that the Company was imprudent and negligent in its

I conclude that the Company has imprudently managed cost recovery for known and measurable anticipated costs for coal ash basin closures in the period prior to the present general rate case. This is an issue not adequately addressed by the majority.

(i) W.S. Lee Steam Station – Inactive Ash Basin and "Borrow Area"

The W.S. Lee Steam Station (Lee Plant) in Anderson County, South Carolina, commenced commercial operations in 1951 and was officially retired as a coal-fired plant in November 2014. Kerin Direct Ex. 4 (Ex. Vol. 16, Part 1, p. 9). Two of the three existing coal units were fully retired; the other was converted to natural gas. The Company's plans for decommissioning and closure of the coal-fired units and the associated waste ash surface impoundments were part of a more comprehensive generating fleet modernization program, which is described in detail in the Company's 2012 Plant Retirement Comprehensive Program Plan. See Doss AGO Cross Ex. 1 (Ex. Vol. 12, pp. 818-839). Under that plan, retired coal-burning units were to be decommissioned and demolished to grade level, and ash ponds were to be closed using a cap-in-place strategy, with long-term monitoring thereafter.

During the period prior to retirement of the coal units, there were four waste ash storage or disposal areas at the Lee Plant. The oldest was a surface impoundment originally constructed in 1951. This impoundment was closed and a new, larger impoundment was constructed on top of the closed basin in 1959. The second impoundment was in use until 1977, when a third impoundment was constructed. The two original impoundments are sometimes referred to in the record as the "inactive ash basin," and other times as the "1951/1959 basins." E.g., DEC's Late-Filed Exhibits in Response to Commission's Request for Closure Plans (March 28, 2018). When use of the 1951/1959 basin was discontinued, the impoundments were dewatered and a soil cover was placed over the ash remaining in them. See Kerin Direct Public Staff Cross Ex. 4 (Ex. Vol. 16, Part 1, pp. 73-110); Kerin Rebuttal Public Staff Cross Ex. 4 (Ex. Vol. 24, Part 2, pp. 171-185). The new impoundment opened in 1977 was subdivided into "primary" and "secondary" sections. Only these two components were actively receiving and storing ash waste when the coal-fired generating units at the Lee Plant were retired in 2014. In addition to the two active impoundments and the inactive ash basin, there was an area to the north of the inactive ash basin, sometimes referred to as the "ash fill area," and other times referred to as the "borrow area." Id. This area contained ash that had been excavated from the impoundments and dry stacked. Both the inactive ash basin

management of the ash impoundments at the Dan River Plant. Kerin Sierra Club Cross Exs. 6-7 (Ex. Vol. 16, Part 1, pp. 401-457). As the Company's counsel acknowledged to the Court, the violations of the Clean Water Act to which the Company pleaded guilty were essentially "negligence-based crimes." Ex. Vol. 16, Part 3, p. 235, Lines 11-12. In the present circumstances, the standards for imprudence and negligence are essentially alike. See, e.g., Hempling, Regulating Public Utility Performance, p. 237 (ABA, 2013); Arizona Pub. Serv. Corp., 21 FERC ¶63,007, p. 65,103 (1982), aff'd in relevant part, 23 FERC ¶61,419 (1983); Appeal of Conservation Law Foundation, Inc., 507 A.2d 652, 673 (N.H. 1986) (describing the prudence standard as "essentially applying an analogue of the common law negligence standard").

and the ash fill area were located on that portion of the plant site bordering the Saluda River.[13]

On April 1, 2014, in the wake of the ash release into the Dan River, Company representatives met with the South Carolina Department of Health and Environmental Control (DHEC) to discuss the status of the inactive ash basin. Interest in the inactive ash basin centered on the fact that there was a 60-inch diameter corrugated metal pipe under the inactive ash basin that had been constructed before 1951 and had been used to carry stormwater runoff from the plant site to the Saluda River, a design that was similar to the corrugated metal piping construction that had failed under the ash impoundment at the Dan River Plant. In addition to this pipe, there were two smaller pipes that had conveyed discharge water from the 1951/1959 basins to the river. None of these three pipes was in use in 2014. In the days before the April 1, 2014 meeting with DHEC, the Company had inspected the three pipes and had found no evidence of any flow in them, or any discharges from them.[14] In a letter to DHEC on April 4, 2014, following the earlier meeting, the Company advised that it planned to grout and seal the three pipes and anticipated submitting plans for this work by April 28, 2014. See Kerin Public Staff Cross Ex. 4 (Ex. Vol. 16, Part 1, p. 76). It is evident that the recent Dan River ash release was much on the minds of the Company and DHEC at this time. The Company's letter stated:

> Unlike the basin at Dan River, there has not been standing water in this inactive basin for many years. The pipes are not discharging to the river, and the risk of a potential release to the Saluda River is low since little water exists in the basin.

Id.

On May 1, 2014, the Company again wrote to DHEC to provide an update and a proposed schedule for permanently plugging the three pipes. Id. at 85-86. Again, on May 8, 2014, the Company wrote to DHEC to advise on the progress of its third-party engineering contractor, Soil & Materials Engineers, Inc., and to discuss in more detail its plans for plugging the 18-inch diameter discharge pipe for the 1959 basin.[15] Id. at 91-92. The Company reported that video inspections had disclosed no evidence of water seeping into or otherwise infiltrating the piping. Further letter reports were made to DHEC

[13] A site diagram and brief explanatory history of these ash disposal areas is contained in Kerin Public Staff Cross Ex. 4 (Ex. Vol. 16, Part 1, pp. 73-110). The summary here largely is based on that exhibit.

[14] During the course of the plea hearing in the Company's criminal case, Company counsel acknowledged that the Dan River ash release had prompted the Company to conduct inspections of all of its concrete and corrugated metal pipes at its various waste ash storage and disposal facilities. Kerin Direct AGO Cross Ex. 7, p. 72 (Ex. Vol. 16, Part 3, p. 246.)

[15] In connection with plugging the discharge pipes for the 1959 basin, the Company also planned to raise the level of the basin dike to provide additional assurance that stormwater runoff that might collect in the basin during a heavy rain event would not overtop the dike after the discharge pipes had been sealed, causing erosion of the dike.

on June 19, June 26, July 3, and on July 30, 2014. Id. at 93-110. Even though the coal-fired units at the Lee Plant were scheduled for retirement in the fall of 2014, and planning work was underway for the much larger effort required to decommission those units and the active waste ash impoundment, it was clear that in April and May, 2014, the situation involving the piping underneath and associated with the closed 1951/1959 basin, had become a central focus of attention. This interest is of significance since the inactive ash basin was not at that time subject to South Carolina's dam safety regulations or any other regulatory regime relating to waste surface impoundments. Likewise, the "ash fill" or "borrow area" was not subject to any permit requirements or to any generally applicable regulation at the time. As it turns out, the inactive ash basin was not, and is not, subject to the EPA's CCR Rule, and, of course, it is not subject to North Carolina's CAMA. I also note that there is no evidence in the record that, during this time, either the inactive ash basin or the "borrow area" were causing, or were otherwise associated with any groundwater or surface water contamination on or in any area surrounding the plant site, including the Saluda River.

Following this sequence of events, on July 17, 2014, DHEC tendered to the Company a draft consent agreement which required the Company to develop and then to implement a remedial plan for the inactive ash basin. See Kerin Rebuttal Public Staff Cross Ex. 4 (Ex. Vol. 24, Part 2, pp. 171-185). This draft consent agreement did not specify the work to be performed by the Company nor did it establish any timetable for that work but, instead, established a procedure for DHEC review, oversight, and approval of whatever work the Company proposed to undertake. The draft stated as a conclusion of law, not supported by any findings of fact whatsoever, that a release or threat of release of hazardous substances had occurred from the inactive ash basin in violation of the federal Comprehensive Environmental Response, Compensation and Liability Act of 1980[16], notwithstanding the fact that coal ash wastes were not themselves classified as "hazardous" for purposes of the Resource Conservation and Recovery Act,[17] or the fact that there was at that time no evidence of any contamination of soils, surface water, or groundwater that could be associated with the inactive ash basin. Id. The draft simply recited that: "Duke Energy is entering into the Consent Agreement out of concern for human health and the environment and will take all necessary steps in compliance with all environmental laws to prohibit future releases from the Site." Id. at 175.[18] Based on the structure and content of the draft agreement between DHEC and the Company and the testimony from both the Company's witnesses and from Public Staff witness Garrett, who has had extensive experience dealing with DHEC in regards to coal ash surface impoundments, I find that it is more likely than not that DHEC lacked any legal basis to impose the consent agreement in the absence of the Company's acquiescence.

[16] 42 U.S.C. §§ 9601-9675.

[17] 42 U.S.C. §§ 6901-6992k.

[18] The draft July 17, 2014 consent agreement contains no findings that there had been any *past* releases.

According to the testimony from witness Kerin, on September 29, 2014, the Company and DHEC entered into a revised consent agreement that required immediate excavation of the inactive ash basin and removal of the ash therein and, additionally, excavation and disposal of the ash in the unregulated borrow area, with all such activity to be completed by December 31, 2017.[19] Tr. Vol. 15, pp. 121-123. Throughout the period leading up to September, 2014, the evidence is clear that both the Company and DHEC were focused on the issue of the corrugated metal pipe running under the inactive ash basin and on the status of the two discharge pipes. For reasons that will be discussed presently, it is significant that the communications during this time period contain no indication that either the Company or DHEC were concerned about the structural integrity or stability of the inactive ash basin's dike. With respect to the impounding dike, all attention was focused on whether the level of the dike should be raised in order to prevent stormwater overflows after plugging of the discharge pipes.[20]

The Company's plan for closure of the active primary and secondary ash basins was to construct a new, on-site lined landfill within the footprint of the secondary basin, to dewater the ash in the basins, and then to excavate the ash and move it to the new on-site landfill. This new landfill would have sufficient capacity to accommodate not only the ash quantities in the active primary and secondary basins, but also the quantities that were contained in the inactive ash basin and the borrow area. Tr. Vol. 21, pp. 24-25. This fact is not disputed by the Company. However, because of the strict timetable established in the September 29, 2014, agreement, the Company concluded that it would be unable to wait for construction of the new on-site landfill before relocating ash from the inactive basin and the borrow area and, instead, needed immediately to excavate the unregulated, closed, inactive ash basin and the borrow area, and then to transport the wastes to an offsite third-party landfill in Homer, Georgia. **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]**

Based on this evidence and on the testimony by witnesses Kerin and Garrett, I conclude that DHEC's and the Company's insistence on immediate excavation and removal of the ash in the inactive ash basin and in the borrow area was a direct and proximate result of the ash spill at the Company's Dan River Plant in February, 2014. I base this on the following factors, among others: (1) that both the inactive ash basin and the borrow area were unregulated, were not subject to any permit requirements or outstanding directives, and did not later become subject to the federal CCR Rule; (2) that

[19] The revised consent agreement, executed on September 29, 2014, was not put into the record in this proceeding by any party, but I have accepted the testimony of witness Kerin as to its contents and substance. It marked a significant change from the July 17, 2014 draft consent agreement, a matter which is not further explained in the record of this proceeding.

[20] Also of interest here are Junis Exs. 14, 15 and 16 (Ex. Vol. 26, Official Exhibits-Public Staff Junis Exhibits 13-23, pp. 9-24) which are a series of communications between the Company and DHEC in the first half of 2014 concerning compliance issues relating to the two active impoundments at the Lee Plant. Among other topics discussed in the communications are the stability of the dams and embankments for the primary and secondary ash ponds and the potential for liquefaction of soils in the event of an earthquake. These communications do not discuss any issues relating to the inactive ash basin or the borrow area.

the inactive ash basin was not subject to South Carolina's dam safety law; (3) that no concern appears in the record concerning any aspect of either the integrity of the inactive basin dike, the discharge pipes, or the corrugated metal stormwater pipe under the basin until immediately after the Dan River spill; (4) that as witness Kerin testified and as the correspondence reveals, the Dan River incident and, more particularly, the risk of failure of corrugated metal piping under the basin was a specific topic of concern to DHEC and was the focus of the parties' attention in the months following the Dan River spill[21]; and (5) that DHEC initially sought to assert regulatory control over the basin through a statute clearly inapplicable to it, evidencing the pressure it was placing on the Company to address its concerns about the basin. I note that none of this history leading to the Company's agreement to commence immediate excavation of the inactive ash basin and the borrow area is discussed in the majority's analysis of this issue.

The Company, seeking to avoid a finding that the Dan River incident was the principal driver of the September 29, 2014, agreement, contends that immediate excavation and removal of the ash from the inactive ash basin was necessary in order to avoid the risks of sloughing of the impoundment dike or, more severely, liquefaction of the soils underneath the dike structure in the event of a major earthquake, and that removal of the ash from the basin would eliminate any concern about a release of ash into the Saluda River in such event. Witness Kerin testified to the point as follows:

> The S&ME report had some recommendations on how do [sic] deal with the steep slopes and how to deal with some stabilization of the dam, but if you think of liquefaction, there is no way to solve liquefaction from a dam modification issue. Liquefaction is the underlying soils below the dam. So those soils were alluvial, which is based on being beside that river over the years. You put that on top -- there was sandy soils, so our core borings indicated that the base of that dam was very susceptible to liquefaction even [sic]. So if you think of what liquefaction is, you take the sand, the ash, you shake it, it basically liquefies and it will move. So the concern here was, below that dam, the base of that dam right along the Saluda River, and that is right -- if you are familiar with that dam, the toe of that dam is on the river -- that any earthquake even or severe shaking of that would cause that earth to liquefy and you would lose the contents. Very similar to what happened in the TVA event, when their dam, the surfaces below, liquefied in Kingston.

Tr. Vol. 15, p. 118.

There are significant discrepancies between the conclusion that the Company wishes the Commission to draw about its decision in 2014 to proceed immediately to excavate the inactive ash basin and the borrow area, and the documentary evidence in the record. These discrepancies are so great that I conclude that the Company's theory is an after-the-fact rationalization, and that based on the evidence of what the Company

[21] In particular, see Tr. Vol. 24, pp. 152-155, where witness Kerin testified that based on reports from his superior, John Elnitsky, who attended meetings with DHEC, the Dan River incident and the similar drain pipes under the Lee Plant basins were a primary focus of DHEC's concerns.

knew, did, and said at the time in 2014, its decision to commence immediate excavation and removal was not based on a concern about the structural integrity of the dike at the inactive basin in the near or intermediate term or the possibility that a seismic event would occur.[22] I summarize these discrepancies in the following itemized points:

1. In response to a pre-hearing data request to the Company submitted by the Public Staff, which requested documents upon which the Company relied in concluding that there were unacceptable risks associated with leaving ash in the inactive ash basin until such time as the new onsite landfill was completed and the ash could then be removed to that new landfill, the Company produced an engineering report and analysis by URS Corporation, dated June 30, 2015 (URS Report). See Garrett Duke Cross Ex. 1, Tab 20 (Ex. Vol. 22, pp. 137-232). More will be said about this report presently. For now I note only that the report proffered by the Company was dated some eight months after the Company had already entered into its September 29, 2014, consent agreement with DHEC and over a month after the Company had already begun excavating the inactive ash basin and transporting the ash offsite. The Company had already made its decision and begun to take action before the URS Report was delivered.[23]

2. The URS Report assessed not only the inactive ash basin and the borrow area, but also the two active surface impoundments. First, among the key findings in the report's executive summary were the following:

   > Imminent Dam Safety Issues: No conditions were observed or identified by analyses completed under Phase 2 that represent a dam safety condition requiring immediate attention.

   Id. at 143.

   Among the other key findings were that the alluvial soils and ash of the inactive basin could be susceptible to liquefaction during the maximum design event earthquake and could be unstable following such an earthquake, and this was the subject to witness Kerin's testimony, as quoted above. *This exact same finding was made in the URS Report with respect to both the active primary and secondary ash basins,* which noted that "for the primary ash pond that is near the design normal pool elevations, it is possible that portions of the pond could breach, releasing its contents." Id. at 209. These identical findings are significant because the Company has contended that it could not responsibly carry the seismic risk identified in the URS Report for the seven-year period

[22] It should not escape notice that there were then, and have been since, no identified structural risks associated with the unregulated borrow area, but the Company also committed in 2014 to immediately excavate and transport for offsite disposal of the ash in the borrow area.

[23] Ex. Vol. 22, pp. 138-232.

required to construct its new onsite landfill and that, therefore, it was necessary to commence excavation and removal of ash from the unregulated inactive ash basin and the borrow area immediately. Yet the Company considered that very same risk to be acceptable with respect to the wastes that would remain in the primary and secondary ash basins until such time as the new onsite landfill was constructed and available for use, notwithstanding that the URS Report identified geotechnical stability and performance issues for the primary ash basin that were as significant as any that were identified relative to the inactive ash basin.[24]

3. The URS Report notes, on page 5, that URS had not done a more detailed analysis of the liquefaction potential for the inactive ash basin due to the fact that ash removal from the basin was already underway, rendering further analysis unnecessary.

The URS Report was preceded by a report prepared by the Company's engineering consultant, Soil & Materials Engineers, Inc. (S&ME), dated September 12, 2014 (S&ME Report), which was only a couple of weeks before the Company committed to immediate excavation and removal of ash from the inactive ash basin and the borrow area. Garrett Direct Ex. 2 (Ex. Vol. 22, pp. 6-43). This S&ME Report is not discussed by the majority in its analysis. The S&ME Report included field and laboratory testing and modelling of both slope stability of the dike and liquefaction potential of the underlying soils in the event of a major earthquake (modeled using a magnitude 7.3 on the Richter Scale, which was the magnitude of the 1886 Charleston earthquake).[25]

The S&ME Report recommended that the Company continue to monitor the basin embankments to observe and detect any changing conditions. It noted that the addition of rip rap material along the river bank would alleviate any short-term risks of surface erosion and shallow sloughing due to river flow along the base of the embankment. The S&ME Report further recommended that ***if*** the Company wished to improve slope stability beyond the existing case, it could undertake to buttress or to flatten the slopes of the embankment, but S&ME did not go so far as to find that the existing condition of the slope was unacceptable. In response to a data request from the Public Staff, the Company admitted that S&ME had not recommended immediate excavation of the inactive ash basin, and that it had provided specific instructions on how to undertake any *optional or elective* changes to the embankment that the Company wished to make. See DEC's

[24] Of course, since the coal units at the Lee plant had been retired in November, 2014, the Company cannot explain this difference by pointing to a need to continue to use the primary ash basin to sluice and store new ash wastes from ongoing and future operations.

[25] The majority states that witness Garrett's proposal that the Company should have delayed excavating the inactive ash basin until the new onsite landfill was available "…would have required trading old risks for new risks." Majority Order at 309. But the "risks" considered in the S&ME Report were not new ones – they had been present since the closure of the inactive ash basin in 1977. As the S&ME Report explicitly noted, the actual historical performance of the dike was a factor to be considered in assessing whether any remedial action was required or was desirable, and that engineering standards for new dikes or impoundments were not necessarily a reliable guide for evaluating existing impoundments with an extended history of actual operation.

Response to Public Staff Data Request No. 58-22, pp. 1-5 (March 23, 2018) (filed as a late-filed exhibit pursuant to my request and the request of Commissioner Brown-Bland, which were made on the record during the evidentiary hearing).

The S&ME Report represents the state of the Company's knowledge at the time it concluded that it would commence immediate excavation and offsite disposal of the contents of the inactive basin, and there is nothing in the S&ME Report that suggests an immediate or near-term risk of any release of materials into the Saluda River while awaiting construction of the new onsite landfill.

Public Staff witness Garrett concurred in the Company's decision to excavate the inactive ash basin and remove its contents to the new onsite landfill at the time it was completed, and I do not take issue with this portion of his analysis. He disputes only the timing of the Company's decision, which necessarily required more expensive transportation and offsite disposal. The majority takes the testimony of witness Kerin, who in period April to September, 2014, was brand new to the coal ash arena and had no first-hand knowledge and minimal prior pertinent experience, at face value. I find, on the other hand, that the testimony of Public Staff witness Garrett, who had first-hand experience in a number of coal ash projects in South Carolina and had negotiated extensively with DHEC, is far more credible on the matters in dispute. See Tr. Vol. 21, pp. 16-17 (setting out witness Garrett's specific experience with ash impoundment closures in South Carolina).

Based on all of the foregoing, I find that the Company's decision to commit in 2014 to immediate excavation and removal of the ash in the inactive ash basin and the borrow area at the Lee Plant was a direct consequence of the atmosphere created by the Company's imprudent management of the impoundments at the Dan River Plant, and was not due to any then-existing concerns about the integrity of the embankment of the inactive basin itself. **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]**

(ii) Dan River Steam Station

The three coal-fired generating units at the Dan River Steam Station (Dan River Plant) were retired in April, 2012, and the process of decommissioning the plant commenced thereafter. Associated with the coal units were two surface impoundments, known as the "primary pond" and "secondary pond," and two areas where dry waste ash had been placed, known as "fill area 1" and fill area 2," respectively. The Company had been anticipating and planning for retirement of the coal units at the Dan River Plant since at least 2008. E.g., Kerin Direct Public Staff Ex. 2, Part 2, pp. 49-53 (complete copy filed in the record by Public Staff March 19, 2018, pursuant to Commission request during the evidentiary hearing).[26] Even earlier, in its 2003 Coal Combustion Ten-Year Plan (2003 Plan) the Company had planned for the management of the ash waste storage and disposal areas in order to maximize use of available land on the plant site. Kerin Direct

[26] References to this exhibit hereafter are to the complete copy of this exhibit filed by the Public Staff as a late-filed exhibit on March 19, 2018.

AGO Cross Ex. 1 (Ex. Vol. 16, Part 2, pp. 123-280). The 2003 Plan concluded that the Dan River Plant had adequate ash waste storage area for at least another twenty years in either greenfield or brownfield disposal cases. The 2003 Plan contemplated a series of measures to provide long-term capacity involving excavating ash from the surface impoundments and then stacking the excavated ash in the two ash fill areas, thereafter covering the fill areas with synthetic caps. See, e.g., Kerin Public Staff Cross Ex. 6 (Ex. Vol. 16, Part 3, pp. 1-49). Total projected spending on these projects through 2013 was estimated to be $1,150,000 in capital costs, and approximately $5,700,000 for operating and maintenance costs.

The Company's 2008 Coal Combustion Products Ten-Year Plan (2008 Plan) continues the operating plan laid out in the 2003 Plan – periodic excavation of the two impoundments in order to preserve capacity followed by stacking the excavated ash in the two ash fill areas. The 2008 Plan noted that due to the plant's planned retirement schedule, conversion to dry ash handling and disposal, a topic considered in the 2003 Plan, would not be pursued. Kerin Direct Public Staff Ex. 2, Part 2, p. 55. At the time, the 2008 Plan contemplated that the ash fill areas would be capped with a synthetic cap and closed in 2011, and contained an estimated project budget for this activity, although it noted that the timing of that project might be re-evaluated depending on the actual plant closure date. Id., p. 142.

As far as the record discloses, when the coal units at the Dan River Plant were retired in 2012, nothing was done immediately to start the process of dewatering the two surface impoundments, notwithstanding the fact that the Company knew that dewatering was the single most important early step to be taken in order to eliminate or reduce the hydraulic pressure of the standing and interstitial water in the basin, and thereby reduce seepage and migration of ash constituents to surface water and groundwater. E.g., Tr. Vol. 15, pp. 33-74.[27] At the time of the February, 2014 ash release into the Dan River, dewatering of the impoundments still had not taken place. Nothing had been done to relieve the hydraulic pressure in the impoundments on the pipes that ran underneath them. The record discloses no external obstacle standing in the way of the Company's taking action to commence dewatering of the ash basins after 2012. The delays were all internal.

On January 22, 2014, a matter of days before the release of ash from the primary pond, the Company received a draft design report from its contractor AMEC Environment & Infrastructure, Inc. detailing the proposed closure of the surface impoundments

[27] Of interest on this point is an undated internal Company document titled "Ash Basin Closure Strategy." AGO Late- Filed Ex. 1, Tab E (filed as part of the evidentiary record on April 18, 2018, and subsequently accepted into the evidentiary record by Commissioner Order dated April 27, 2018). Internal evidence indicated that the document was most probably prepared sometime in 2013. Discussing "timing considerations" relating to ash basin closures the document notes: "[d]ewatering the ash basin in accordance with the NPDES permit will over a relatively brief time reduce and/or eliminate seepage which the company is currently addressing." Id. Addressing the Court at the sentencing hearing in the Company's criminal case, Company counsel stated: "The thing about seeps is that the easiest way to control a seep is to let us dry out the coal ash and move it and close those basins." Ex. Vol. 16, Part 3, p. 253.

(January 2014 AMEC Plan). Kerin Public Staff Cross Ex. 6 (Ex. Vol. 16, Part 1, pp. 111-137). The proposed closure design was described as follows:

> The preferred closure concept is the hybrid approach described as follows: move all Primary and Secondary Pond ash into the Ash Fill 1 and 2 area; close Ash Fill 1 and 2 in place with an engineered cover system; remove Primary and Secondary Pond embankments and re-use the soil for cover system construction and pond area restoration; grade the ash pond areas to promote drainage and stabilization; and remediate groundwater (either passively or actively) and implement long-term groundwater monitoring.

Id. at pp. 118-119. This closure concept had been prefigured in the Company's operating plan for the waste units at Dan River as set forth in the 2008 Ten-Year Plan. In the Company's internal planning documents, this "hybrid approach" was sometimes referred to as a "brownfield" strategy, both terms referring to the construction of a new landfill disposal facility over top of or within the perimeter of an existing area of ash fill, capping the existing fill area in place and using the newly constructed landfill for future waste disposal or for relocation of existing waste from other storage areas. It is contrasted with a "greenfield approach," which referred to the construction of a new landfill on land not previously used to dispose of wastes. The January 2014 AMEC Plan concept design plan was consistent with the manner in which the Company had been operating and managing the impoundments since at least the time of the 2003 Ten-Year Plan.

By April 28, 2014, less than two months after the February, 2014 release into the Dan River, focus had shifted from the preferred concept in the January 2014 AMEC Plan. On that date AMEC submitted to the Company a second report evaluating various possible locations for an *off-site* "greenfield" landfill for disposal of the waste ash from the Dan River Plant. See Kerin Public Staff Direct Ex. 7 (Ex. Vol. 16, Part 1, pp. 138-75). By November 13, 2014, the Company had submitted to the North Carolina Department of Environmental Quality (DEQ)[28] what became, in concept, the closure plan for which the Company now seeks cost recovery in this case. Id. at 176-99. That plan, in pertinent summary, provides for removal of the ash in fill area 1, for transportation and offsite disposal of that ash followed by construction of an on-site lined landfill within the footprint of ash fill area 1. The ash waste in the two impoundments, after first being dewatered, would then be excavated and permanently disposed of in the newly constructed onsite landfill. This plan differed from the January 2014 AMEC Plan in one critical respect – the January 2014 AMEC Plan did not contemplate excavation and offsite disposal of the ash from ash fill area 1 prior to construction of a new landfill in that location.

At the hearing in this case, Company witness Kerin and Public Staff witness Moore vigorously debated the possibility that the Company could have constructed a new lined landfill on another portion of the plant site (a "greenfield" site), and thereby avoided the costs incurred to excavate, transport, and dispose of offsite the ash in fill area 1. I do not

[28] Formerly known as the North Carolina Department of Environment and Natural Resources (DENR). DENR's name changed to DEQ effective September 18, 2015.

find it necessary to resolve that disagreement. Instead, I conclude that but for certain provisions contained in CAMA that were, I believe, directly connected and causally related to the Dan River ash spill in February, 2014, the Company would have been able to implement the January 2014 AMEC Plan, thereby avoiding the excavation, transport, and offsite disposal of the ash in fill area 1. I arrive at this conclusion based on the considerations set forth hereafter.

The bill that eventually was enacted as CAMA was originally filed on May 14, 2014, as S. 729, bearing the short title “Governor’s Coal Ash Action Plan.”[29] Section 10 of the bill singled out two of the Company’s coal-fired generating plants, Dan River and Riverbend, and required prompt submission of closure plans for the surface impoundments at those plants and for permanent disposal of the ash in a lined structural fill, a lined landfill, or an alternative approved by DEQ. Dan River and Riverbend were the only two plants in the Company’s fleet called out by name in the proposed legislation. The first edition of the filed bill contained recitals specifically referring to the Dan River Plant ash release and the fact that wastes from the release had settled into river bottom sediments, requiring extensive remediation.

The bill took substantially its final form in the Second Edition, which was adopted by the Senate Agriculture, Environment and Natural Resources Committee on June 17, 2014. All recitals in the original bill were dropped; however, the specific provisions targeting the Company’s Dan River and Riverbend plants were retained in modified form. In all material respects for purposes of the present discussion, the bill remained unchanged thereafter until its enactment with an effective date of September 20, 2014. N.C.S.L. 2014-122.

CAMA contains a comprehensive scheme for regulation and eventual closure of all waste ash surface impoundments grounded on a risk-based priority classification – low, intermediate, and high – with the requirements for operation and closure, and the associated deadlines, increasingly stringent as the risk classification level increases. The determination of risk classification is to be made by DEQ on a site-by-site basis, based on extensive analysis and public input, except in four cases. In those four specific cases, the General Assembly pre-empted the general statutory scheme and declared that those sites were to be classified as high-priority sited and imposed a final closure date for the coal combustion residuals impoundments at those plants of August 1, 2019.[30] Those four sites, out of the entire fleet of the two Duke Energy affiliates operating in North Carolina, were Dan River, Riverbend, Asheville, and Sutton. All other sites were declared intermediate-risk for interim purposes with final risk classification to be established by DEQ later. The record in this case establishes that all of the Company’s remaining waste surface impoundments were ultimately classified by DEQ as low-risk under CAMA. Tr. Vol. 16, pp. 38-42.

[29] N.C. Gen. Assembly, S. 729. Reg. Sess. 2013-2014 (2014). The complete legislative history of S. 729 is available at https://www2.ncleg.net/BillLookup/2013/S729.

[30] N.C.S.L. 2014-122, § 3.(b).

The most significant features of the final low-risk classification of the waste impoundments at the Company's other plants are an extended target date for final closure in 2029 and the potential opportunity to use a cap-in-place closure strategy for the impoundments, that being the same closure strategy for which the Company had been planning and preparing since the mid-2000s. In other words, as CAMA is now being implemented, the Company's pre-CAMA preferred closure strategies are still potentially available for all of its plants, except Dan River and Riverbend.[31]

Based on the entire record, I conclude that the General Assembly's pre-emption of the general regulatory regime and its peremptory directive concerning closure of the impoundments at the Dan River Steam Station was a direct consequence of the Company's February, 2014 ash release into the Dan River. The General Assembly's action in this regard cannot be based on any other factors evidenced in this record that differentiate the Dan River impoundments from those at the Company's other coal-fired generating plants.[32] The extensive evidence presented by the Public Staff and other intervenors concerning seeps and groundwater exceedances at all of the Company's plants does not show any evidence of environmental compliance issues, groundwater exceedances, seeps, or other environmental contamination associated with the two Dan River impoundments that are materially greater than or different from those at any of the Company's other plants. <u>See, e.g.</u>, Ex. Vol. 26, p. 61; Ex. Vol. 16, Part 2, pp. 35-80; Wells Public Staff Cross Ex. 2, p. 4 (complete copy filed on April 5, 2018, pursuant to the Commission request's on the record during the evidentiary hearing); Kerin Sierra Club Cross Ex. 2; AGO Late-Filed Ex. 1, Tab K.

Several intervenors and the Company have wrestled over whether or not the entirety of CAMA can be attributed to the Dan River ash release. I do not take a side in that debate but instead reach a more limited conclusion here – that based on the internal structure and history of the legislation that became S.L. 2014-122, certain of its specific provisions *can* be directly linked to the February, 2014 ash release at Dan River. It is the consequences following from those specific provisions that occupy me here.

The legislative dictate that Dan River Plant impoundments be treated as "high-risk" had substantial and costly consequences for their method of closure. The Company's pre-spill closure design concept, which was consistent also with the operating history of

[31] A high level summary description of the Company's pre-CAMA closure strategy for its ash basins is provided in Doss AGO Cross Ex. 1 (Ex. Vol. 12, pp. 818-839.) More detailed discussion of the Company's pre-CAMA closure strategies are contained in several of the documents referred to in Section I.C. hereafter.

[32] From the record presented it is not possible to draw a firm conclusion as to the rationale for the "high risk" designation of the Riverbend plant. Certainly, that designation cannot be attributed to the ash release at the Dan River plant in February, 2014, and the Company's mismanagement of the impoundments at Dan River. At the time CAMA was enacted the Riverbend plant was, however, subject to two pending suits alleging environmental contamination at the plant associated with waste ash impoundments, one in Mecklenburg County Superior Court brought by DEQ and the Southern Environmental Law Center and one pending in the United States District Court for the Western District of North Carolina brought by the Catawba Riverkeeper. See Junis Exs. 17 and 18 (Ex. Vol. 26, Official Exhibits-Public Staff Junis Exhibits 13-23, pp. 25-34.)

the impoundments, had been to consolidate the ash contents from the two impoundments in the unlined ash fill areas and then to cap the combined ash from the fill areas and the impoundments with a synthetic seal and a vegetative layer. This was not only the least cost closure method; it also could be implemented on a reasonably short schedule once the surface impoundments had been dewatered. (For estimates of cost and time to closure, see AGO Late-Filed Ex. 1, pp. 135-165, Tab J: Plant Demolition and Retirement Presentation for the Executive Governance Committee, dated October 14, 2013. Dan River ash basin closure costs commencing 2013 and concluding 2017 estimated to total $23,993,000.) Of course, we know now that the Company delayed commencement of ash basin closure from the proposed 2013 start date. We also know that the Company's total cost estimate for closure of the Dan River impoundments, not including inflation costs, are now estimated to be in excess of $222,994,117. See Revised Kerin Ex. 11 (March 22, 2018).

CAMA's high-risk classification of the Dan River Plant impoundments foreclosed the Company's earlier preferred closure plan because of two of the law's provisions. Section 3.(a) of CAMA would have permitted the Company to construct a new coal combustion residuals landfill on top of either of the two ash fill areas and then to remove the ash wastes from the surface impoundments for disposal in the newly constructed landfill. Such a new landfill would have required a liner system over the existing ash and one beneath the ash excavated from the impoundments and placed in the new landfill. The closure options permitted under Section 3.(a) of CAMA, however, do not include excavation of the ash from the two impoundments, and then consolidation of the fill ash and the excavated impoundment waste ash *in situ* with a final cover or cap over the combined waste but without a liner under the ash.

Although as just noted Section 3.(a) permitted the Company to construct a new, lined landfill on top of the ash fill areas, Section 5.(a) of CAMA placed a moratorium on the Company's ability to construct any new landfill on the site of ash fill area 1, meaning that the Company could not immediately begin the process of constructing a landfill in or over ash fill area 1 until that moratorium expired.[33] As witness Kerin testified, the moratorium caused considerable anxiety about the Company's ability to meet CAMA's August 1, 2019 deadline for final closure of the surface impoundments at Dan River Plant.

The moratorium only applied to new "coal combustion residuals landfills," which were landfills constructed on top of areas presently or previously used for coal ash waste storage or disposal, meaning that the Company was free during the period of the moratorium to explore options for construction of a new landfill on a "greenfield" site. During the period between February 2, 2014, and November, 2014, when the Company submitted its proposed action plan to DEQ, the Company did investigate and consider its "greenfield" options. I concur in the majority's findings that neither the Hopkins tract, which was investigated by the Company, nor an onsite area west of the existing plant, recommended by Public Staff witness Moore, were reasonably available alternatives and

[33] The moratorium was to expire and did expire on August 1, 2015, pursuant to Section 5.(c) of CAMA. N.C.S.L. 2014-122, § 5.(c).

that the Company acted prudently in declining to pursue these "greenfield" options. This does not, however, explain why the Company commenced immediate excavation and offsite disposal of the wastes in ash fill area 1, an area that was not itself subject to CAMA's requirements nor to the (at that time pending) CCR Rule. The Company cannot defend this decision on the grounds that excavation and offsite disposal of the ash from fill area 1 allowed it to move forward more rapidly with construction of a new onsite landfill. Excavation of ash fill area 1 did *not* exempt an attempt to construct a new landfill in that area from the moratorium imposed by Section 5.(a) of CAMA. This is so because "coal combustion residuals landfills," whose construction was subject to the moratorium, were defined in G.S. 130A-290(a)(2c), as that statute was amended by CAMA, to mean:

> …a facility 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 of such combustion products, including, but not limited to, landfills, wet and dry ash ponds, and structural fill facilities.

(emphasis added.) Excavation of ash fill area 1, an unregulated facility, did not accelerate the Company's ability to construct a new landfill on that area and did not, therefore, enhance its ability to meet CAMA's mandated final closure deadline of August 1, 2019.

Nor was excavation and offsite disposal of the ash in fill area 1 necessary in order to enable the construction of a new landfill in that area. Again, Section 3.(a) of CAMA permitted the excavation and disposal of ash wastes from the two surface impoundments in a new "coal combustion residuals landfill," which as noted in the definition quoted above, is a facility located "…wholly or partly on top of a facility that is, or was, being used for disposal …" of waste coal ash.

From a close review of witness Kerin's testimony, I conclude that the Company's decision to commence immediate excavation and offsite disposal of the wastes in ash fill area 1 was not based on any consideration of least-cost options, was not dictated by CAMA, was not required in order to enhance the Company's ability to comply with CAMA, and did not in fact accelerate the construction of a landfill within the footprint of ash fill area 1. Instead, I conclude from the testimony that the Company's actions were in fact driven by the pressure it felt in the aftermath of the Dan River release to, put in the vernacular, "do something, do anything, just do something." Tr. Vol. 25, p. 27-28; Tr. Vol. 7, pp. 13-15. My conclusion is further confirmed by the fact that the internal processes for bidding and contracting for excavation and offsite disposal of the ash from the Dan River ash fill commenced in July, 2014, and bids were in hand by October 9, 2014. Kerin Direct Public Staff Direct Ex. 5 (Ex. Vol. 16, pp. 111-113). This time period coincides with the movement of S. 729 through the legislative process, and it *precedes* the Company's submission of its excavation plan for Dan River to DEQ on November 13, 2014. Kerin Direct Public Staff Cross Ex. 9 (Ex. Vol. 16, pp. 181-203).

In consideration of the foregoing, I would deny the Company's request to recover **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]** spent for excavation, transport, and offsite disposal of the wastes from ash fill area 1. These costs are amounts that would not have been expended under the Company's preferred closure plan embodied in the January 2014 AMEC Plan, and are therefore identifiable and quantifiable. Based on my conclusion that the Company's imprudent management of the surface impoundments at Dan River, resulting in the ash release into the Dan River in February, 2014, is the direct cause of the Company's inability to implement the preferred closure plan, I likewise would disallow all costs incurred by the Company for closure activities at the Dan River Plant in excess of amounts otherwise required to implement the January 2014 AMEC Plan. Unfortunately, however, the record does not include any cost estimates for the January 2014 AMEC Plan, and it is most likely that the occurrence of the ash spill on February 2, 2014, pre-empted any further development of such cost estimates. In the event the matter is brought before the Commission in the future and in a proper procedural context, the question whether these excess costs can be quantified will warrant further inquiry.[34]

C. The Company's Handling of Cost Recovery for Anticipated Waste Ash Disposal Costs

I do not disagree with the majority's decision to permit the Company to account for its ongoing and future ash basin closure costs in accord with SFAS 143, at least as it pertains to the closure of ash storage and disposal facilities that are subject to one or more of the federal CCR Rule, CAMA, or applicable final judicial and/or administrative orders.[35] My concern in the present discussion centers on the manner in which the

[34] The Company's Riverbend plant was, like the Dan River Plant, also pre-emptively designated by the General Assembly in CAMA as a "high-risk" site. The Company's preferred pre-CAMA closure strategy for Riverbend had been to cap the existing impoundments in place, but this option was foreclosed by CAMA. Some of the Company's internal documents, however, suggest an awareness by the Company that the cap-in-place concept might not have been ultimately viable at Riverbend because the plant was located in an area designated as a "critical watershed" for public drinking water supplies. See., e.g., Kerin Direct AGO Cross Ex. 2, p. 253. For this reason, among others, I do not believe the record would support any finding that the Company's imprudent actions or omissions are responsible for the closure strategy ultimately adopted and implemented for the Riverbend plant.

[35] The central focus of all parties in this case has been on the surface impoundments used to store coal ash wastes. These impoundments are subject to both the CCR Rule and CAMA, and have been the subject of several judicial and administrative decrees. Over time, the Company has operated other ash storage and disposal facilities at some of its plants that are not regulated under CAMA, the CCR Rule, or any other regulatory regime. The record does not permit a determination as to whether or not the costs of closure of all of these dry storage areas qualify for accounting treatment under SFAS 143 or whether, instead, they should continue to be recorded and reported under the principles set out in SFAS 19. In its discussion of ARO accounting the majority order refers to and discusses the December 21, 2015 letter from Brian Savoy (Savoy Letter), notifying the Commission that the Company would implement SFAS 143 accounting treatment for its waste ash basin closure costs. One point in the Savoy Letter bears upon a subsidiary issue but requires comment here. The letter states: "Coal Ash Basin costs that relate to activities outside the scope of the aforementioned legally required activities (e.g., Federal CCR rules and the NC CAMA legislation) are being expensed immediately as Operations and Maintenance (O&M) expense." In the course of the hearings on the Company's current application, the Company was asked whether the closure costs associated with non-CAMA and non-CCR Rule regulated sites, specifically the inactive ash basin and the borrow area at the Lee Plant, were included in the Company's reported ARO liabilities.

Company accounted for and treated for ratemaking purposes the anticipated costs for closure of the waste ash storage and disposal facilities before it established ARO accounting for those costs. This is a topic not addressed by the majority in its opinion, and I believe this omission is error.

Before the promulgation of SFAS 143, and afterward for all cases that do not fall within the jurisdictional scope of SFAS 143, costs expected to be incurred upon the retirement and decommissioning of a long-lived asset were typically estimated as part of the terminal net salvage value of the asset, which was a component of depreciation. For regulated entities these anticipated costs of removal were included in allowed depreciation expense and were collected in rates. Costs of removal include such items as dismantlement and demolition of structures, sale of salvaged equipment and materials, site restoration, and any necessary environmental remediation costs. When costs of removal were expected to exceed the salvage value of reusable and useful facilities, equipment and materials, terminal net salvage value would be a negative number, and this would serve to increase the annual depreciation expense associated with the long-lived asset. See, e.g., the discussion in Doss Ex. 3, p. IV-2 (Ex. Vol. 12, p. 787). Typically, though not in all cases, accumulated depreciation was recorded for financial statement reporting purposes as a "contra asset," that is, as a deduction from the carrying value of the associated asset on the balance sheet. Usually, though again not always, costs of removal were not adjusted for future inflation or discounted to present value, although they would be subject to adjustment according to periodic updates to depreciation studies and resulting changes to depreciation rates.[36]

The Company's position in this case is that it first became subject to the financial statement reporting requirements of SFAS 143 upon the enactment of CAMA and the adoption of the CCR Rule. While I believe an argument can be made from the evidence presented in this case that earlier application of SFAS 143 might have been required in the case of at least some of the Company's waste ash units, for purposes of the present discussion, I have accepted the Company's position concerning the triggering events for conversion from traditional depreciation accounting for costs of removal to accounting under SFAS 143.[37]

Because it is the Company's position that the September, 2014 consent agreement triggers ARO accounting for these two waste units, the Company reported in its April 6, 2018 filing showing that the costs associated with these two facilities were included in reported ARO liabilities. However, that letter appeared to speak more generally also, saying that estimates and actual expenditures "… are not tracked on a basin-by-basin basis, but on a site-by-site basis." This statement needs to be reconciled with the portion of the Savoy Letter quoted above. I believe the Commission should direct the Company to identify all such unregulated waste units for which closure tasks are being performed and for which costs are being incurred and confirm that no portion of those costs are included in the ARO liabilities reported in Kerin Direct Ex. 11 in this case or in the allowed amounts that are being deferred and amortized by the Majority Order in this case.

[36] This summary is largely drawn from the more detailed explanation of the concepts contained in SFAS 143 and SFAS 19.

[37] In brief summary, the argument would be that final closure of ash storage and disposal facilities upon retirement was a known requirement under the regulatory regime established pursuant to the Clean

It is likewise the Company's position in this case that before its adoption of ARO accounting for the waste impoundment closure costs, it had not included any estimated costs for such closures in its estimation of terminal net salvage values for the generating plants of the impoundments served, and did not, therefore, include any such amounts in its depreciation rates requested and approved under G.S. 62-133(b)(3). Thus, the Company did not collect any such amounts from ratepayers in prior rates. Company witnesses Spanos and Kopp, who prepared and explained the depreciation study offered by the Company in this case, testified that the depreciation study and the requested rates based on that study included no costs of removal for the waste ash impoundments and that, moreover, the depreciation studies and requested rates in the Company's prior rate cases in 2007, Docket No. E-7, Sub 828; in 2009, Docket No. E-7, Sub 909; in 2011, Docket No. E-7, Sub 989; and in 2013, Docket No. E-7, Sub 1026, likewise had included no amounts for costs of removal of the ash impoundments. *They testified that this was so because they had not been asked to include any such elements of cost in their depreciation studies and had been given no information on the subject.* See Tr. Vol. 9, pp. 124-125.[38] Based on this evidence, I find it legitimate to ask whether it was reasonable and prudent for the Company to have omitted all costs of removal for the ash impoundments from its requested depreciation rates in any of its rate cases prior to this one and, if not, what consequences should follow from that omission.

Other evidence in the case, notably Fountain AGO Cross Ex. 6 (Ex. Vol. 10, pp. 609-694) establishes that the Company *did* estimate negative terminal net salvage values for its coal-fired generating plants, *did* include those negative values in the calculation of its requested depreciation rates, and *did* include those negative values in rates collected from customers. Apparently, however, those negative values addressed only plant decommissioning costs other than costs of closure of the waste ash impoundments at the coal-fired plants. Fountain AGO Cross Ex. 6 is a slide presentation titled, "Ash Basin Closure Update," dated January 13, 2014, only days before the ash release at the Dan River Plant, made to the Company's Senior Management Committee on the status of the Company's activities and plans, and those of its regulated affiliates, relative to management of coal ash wastes. Among the topics covered in the presentation

Water Act, and that the costs of closure were reasonably subject to estimate, and in some cases were in fact estimated by the Company, well before the enactment of CAMA or the CCR Rule. In any event, I do not base my conclusion here on any finding that the Company should have requested approval of ARO accounting any sooner than it did.

[38] Under the transition provisions in SFAS 143, when ARO accounting treatment is established for an existing long-lived asset for which depreciation has been and is being taken, the accumulated depreciation is incorporated in a cumulative adjustment to the financial statement, essentially being taken as a credit or reduction of the amount of the recognized and recorded ARO liability. If, as is the testimony in this case, no costs of removal had been collected in depreciation expense, then no credit would have been booked to the ARO liability recorded when the Company adopted SFAS 143 treatment for its ash impoundment closure costs.

was the recovery of costs associated with closure of the ash basins at each of the Company's coal-fired generating plants.[39]

One presentation slide discloses that the Company had collected through depreciation expense costs of decommissioning for its coal-fired plants of some $224 million and that it was possible that some or all of this amount could be tapped to offset a portion of expected costs for closure of the ash basins.[40] At the time of the presentation, the Company's costs to close the ash impoundments, assuming, as in fact turned out to be the case, that the wastes would retain their non-hazardous classification, was estimated to be approximately $610 million. Again, though, the accumulated cost of removal amount for the coal-fired plants, according to the Company's testimony presented in this case, did not include any amounts for the ash impoundments themselves, so any use of the accumulated amount would have potentially left the Company facing insufficient cost recovery for its other plant decommissioning costs.[41]

A final bit of confirmation that the Company's depreciation expense included in its rates did not include any amounts for costs of closure of its waste ash impoundments comes from the application in Docket No. E-7, Sub 1110, which is the Company's application for a regulatory accounting order allowing it to use ARO accounting for expected ash basin closure costs. In its filing, a joint filing with its affiliate DEP,[42] the Company commented that DEP had been collecting as part of costs of removal a specifically earmarked sum for coal ash impoundment closure costs since its last general rate case in 2013. See, e.g., Docket No. E-2, Sub 1023. Nothing similar was disclosed or reported with respect to the Company's own posture on the subject. See also, AGO Late-Filed Ex. 1, Tab L, p. 25, stating: "DEP in the Carolinas, very recently started including recovery for specific ash pond closure costs in their COR rates. DEC still does not have specific related ash pond closure costs in the COR rates."

The Company very clearly knew that costs of removal upon plant decommissioning were a proper component of terminal net salvage values and thus a proper and

[39] I note that this presentation, and most of the other documents I will review, were all dated prior to the enactment of CAMA, prior to the adoption of the CCR Rule, and prior to the Company's plea agreement in its federal criminal case.

[40] This amount is referred to as a "reserve," but it did not represent a segregated fund in the same sense as, say, the nuclear decommissioning trust fund. It instead represented amounts included in rates pursuant to G.S. 62-133(b)(3), but, as noted in the presentation, the Company would nonetheless have to identify a source of cash for the expenditures to which this "reserve" had been accumulated. In addition to the amount separately identified as accumulated costs of removal for the steam plants, the document also disclosed the total accumulated costs of removal for all other asset groups other than nuclear plant, including non-coal generating units, transmission system assets, and distribution system assets.

[41] The same information contained in Fountain AGO Cross Ex. 6 is also provided in a post-hearing exhibit filed by the Attorney General in response to questioning by Commissioners concerning the possible existence of other documents addressing the subject matter of Fountain AGO Cross Ex. 6 See AGO Late-Filed Ex. 1, Tab L.

[42] The Company's filing is assigned Docket No. E-7, Sub 1100. The companion filing by DEP was assigned Docket No. E-2, Sub 1103.

recoverable element of depreciation expense. Should it have included costs of closure for the waste impoundments in its broader estimate of decommissioning costs and, if so, when should it have done so? Answering this question requires, I believe, examination of two things: the development of industry standards and best practices concerning the decommissioning of coal-fired generating plants and their associated waste ash storage and disposal units, and the Company's own internal policies and planning for the retirement of its fleet of coal-fired plants, including the associated ash impoundments, in the time period before the enactment of CAMA in 2014 and adoption of the final CCR Rule in 2015.

The earliest evidence in the record bearing upon these questions is contained in the Electric Power Research Institute's (EPRI's) Coal Ash Disposal Manual, Second Edition, published in October, 1981. Kerin Sierra Club Cross Ex. 4 (Ex. Vol. 16, Part 1, pp. 281-356; complete report filed by Sierra Club on March 15, 2018). The manual is a comprehensive treatment of the then state-of-the-art theory relative to a number of topics, including procedures and practices for closure of waste ash storage and disposal facilities. In its scope section, the manual explains:

> The purpose of Section 8, Site Reclamation, is to present information on site reclamation procedures for ash disposal areas. Because of increased environmental awareness, increased concern for site aesthetics and resulting public opinion, and more stringent environmental regulations, efforts to reclaim and revegetate disposal sites have recently accelerated; however, there is considerable confusion regarding which methods are appropriate …. To assist utility personnel in dealing with site retirement procedures in their area, this section gives specific guidance to effective and economical site retirement and revegetation procedures, as well as sources of additional information and assistance.

Id. at 287.

Section 8 of the manual contains an extensive technical and environmental analysis of methods of retirement and closure for ash storage and disposal facilities, including landfills and surface impoundments. The preliminary scope statement for Section 8 reads:

> The advent of recent federal and state laws involving clean water and waste disposal standards has created a need to closely manage the progression and final closure of ash disposal sites.

Complete EPRI Report filed by Sierra Club, p. 8-1 (March 25, 2018).

This EPRI Report is of particular interest because two of the field sites studied and reviewed in the manual were the Company's Allen and Marshall Steam Stations. In Section 6, the manual describes activities being undertaken by the Company at the inactive ash basin at its Allen Plant to experiment with different types of soil cover and different types of revegetation following decommissioning of the basin. It was clear that as early as 1981, closure and reclamation of retired ash storage and disposal facilities was a topic for which utilities were planning and were expected to be planning, and that the Company itself was already experimenting with closure techniques at its Allen Plant.

In August, 1982, EPRI published a second report titled Manual for Upgrading Existing Disposal Facilities, which addressed practices, standards, and options for addressing deficiencies identified in the course of operating existing ash storage and disposal facilities. Kerin Sierra Club Cross Ex. 2 (Ex. Vol. 16, Part 1, pp. 224-262). The manual notes that its purpose was "… to provide the industry with detailed information about design features, equipment selection, and specific procedures for evaluating current disposal system suitability and selecting optimal retrofit systems for existing disposal facilities." Id. at 226. The EPRI Manual was based on survey research and field site research. Summarizing the deficiencies most often noted in field inspections, the report identified four of particular note, one of which was "closure/post closure plans were inadequate or nonexistent." The manual included not only procedures and recommendations for upgrading facilities and correcting deficiencies but also a methodology for calculating the costs of various upgrades.[43]

By not later than the 2000s, the matter of retirement and decommissioning of coal-fired generating plants constructed in an earlier era had become a topic of greater focus. In November, 2004, EPRI published another manual, this one titled Decommissioning Handbook for Coal-Fired Power Plants. Ex. Vol. 10, pp. 695-782. The manual alerted its users that:

[43] This manual is of particular interest in light of witness Kerin's testimony that in the absence of a regulatory directive to do so, it would not have been reasonable for the Company to modify existing ash impoundments that were still receiving wastes and operating under NPDES permits. Tr. Vol. 14, p. 110. I find that the EPRI Manual confirms that the "minimum required by law" standard of operation advanced in some of the Company's testimony through its witnesses Kerin, Wright and Wells is simply wrong. In its preliminary pages, the EPRI Manual notes:

> Potential deficiencies in utility waste disposal practices may be defined by two sets of standards:
>
> -The disposal practice does not comply with specific federal and/or state regulatory requirements.
>
> -The site has the potential to contaminate the environment.
>
> This seemingly redundant statement is important to any assessment of disposal site deficiencies. Identification and correction of regulatory deficiencies do not necessarily preclude the possibility of past or future environmental degradation by the site. Conversely, known degradation cannot be corrected by simply conforming to the regulations.

Ex. Vol. 16, Part 1, pp. 240-241.

The 1982 EPRI manual is not the only document in the record that communicates this same point. A minimalist view of the requirements of "prudence" simply does not comport with actual industry practices and standards or, as we shall see, with the Company's own view, at least as set out in documents authored prior to this case.

> [t]here are serious issues in plant site decommissioning, most of them environmental. The disposal of many years of waste products – ash, water, oils, chemicals – and the removal of asbestos, PCBs, lead products, etc., requires both an understanding of the extent of the contaminations as well as the best methods of removing and disposing of the substances.

Id. at 704. Discussing the various tasks and costs that could be expected as part of the retirement of a plant, the manual later observed that "[c]losure of surface impoundments and landfills probably will be the most expensive tasks undertaken during a decommissioning project," (Id. At 722), and followed this with the explanation that

> [c]losure of most surface impoundments will require drainage, placement of an impermeable cap, and topping with soil and a vegetative cover. … The caps for the impoundments will require continued maintenance to maintain the site contours, vegetative cover and drainage. Some impoundments will require the installation and monitoring of groundwater wells. The waste in other surface impoundments may be excavated for disposal offsite, and the impoundment backfilled with clean material.

Id. at 724. The manual provided three case studies of plant decommissioning, along with a discussion of the estimated or actual costs incurred. One of the examples was Georgia Power Company's Arkwright Plant, which had ceased operations in 2002, and where final site cleanup was expected to be completed in 2006. The study reported that the costs for closure of waste ash surface impoundments at the Arkwright plant were estimated to be $10,700,000, or some 56.3% of total decommissioning costs net of salvage recovery. Id. at 753. For the Tennessee Valley Authority's Watts Barr plant, finally retired in 2000, the costs for closure and remediation of both dry ash units and surface impoundments were estimated to be $9 million, out of a total cost range estimated to be between $17 million to $25 million in 2000 dollars. Id. at. 754. From the Decommissioning Manual it was clear that the costs of closure of waste ash disposal facilities would not be a trivial or *de minimis* item.

The Company was not unaware or unmindful of the industry practices and learnings evidenced in reports and studies such as these three EPRI manuals and had incorporated them into its own internal policies.[44] Based on the entire record, I conclude,

[44] For brevity, I have selected these three EPRI documents as representative of industry knowledge and practices. The record contains numerous other documents that are fully consistent with and support the conclusions I draw here, including Junis Public Staff Exhibit 4 (Environmental Control Implications of Generating Electric Power from Coal, Argonne National Laboratory, December, 1976); Kerin Sierra Club Cross Ex. 3 (Los Alamos Scientific Laboratory, The Disposal and Reclamation of Southwestern Coal and Uranium Wastes, May, 1979); Junis Public Staff Ex. 9 (Proceedings of the American Society of Civil Engineers, Water Quality Issues at Fossil Fuel Plants, October, 1985, including a case study of releases of selenium from the Company's Belews Creek Steam Station); Kerin Sierra Club Cross Ex. 5 (EPA Report to Congress, Wastes from the Combustion of Coal by Electric Utility Power Plants, 1988); Wells Public Staff Cross Ex. 6 (Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal from Coal-Fired Electric Generating Plants, June, 1985, including in particular a field evaluation and analysis of coal waste handling practices and environmental conditions at the Company's Allen Steam Station; and Ex. Vol. 12, pp. 220-290; and Wright, Public Staff Cross Ex. 5 (EPA Office of Solid Waste, Coal Combustion Waste Damage

on a conservative basis, that by not later than the time of its 2009 general rate case, and most likely sooner, the Company had formed an understanding that: (1) permanent closure of its waste ash storage and disposal facilities would be required when the associated coal-fired generating units were retired, if not sooner; (2) closure of these waste units would constitute a substantial portion of the total costs of decommissioning the plants; (3) planning and investigation of options and development of timetables should begin well in advance of the time of actual plant retirement; and (4) provisions for cost recovery of such closure costs should be developed. These points are extensively developed and documented in a series of internal Company documents, including the following:

- Ten-Year Coal Combustion Products Plan, 2003 (Kerin AGO Direct Cross Ex. 1)
- Ten-Year Coal Combustion Products Plan, 2008 (Kerin Direct Public Staff Cross Ex. 2)
- Duke Energy Environmental Management Program for Coal Combustion Products, dated May 29, 2007, (Kerin AGO Direct Cross Ex. 3)
- Environmental Management Program for Coal Combustion By-Products, dated June 27, 2007 (Kerin AGO Direct Cross Ex. 5)
- 2012 Plant Retirement Comprehensive Program Plan (Doss AGO Cross Ex. 1)
- Guidance on Developing Closure Plans for Ash Basins, September 27, 2012 (AGO Late-Filed Ex. 1, Tab A)
- Ash Basin Closure Strategy, (AGO Late-Filed Ex. 1, Tab E)(undated, but from internal evidence in the document likely dated in 2013)
- Demolition and Plant Retirement Presentation, dated February 16, 2013 (AGO Late-filed Exhibit 1, Tab F)
- Environmental Talking Points for Presentation to Board of Directors, August 27, 2013 (AGO Late-Filed Ex. 1, Tab I)
- Plant Demolition and Retirement Presentation for the Executive Governance Committee, October 14, 2013 (AGO Late-Filed Ex. 1, Tab J)
- Ash Basin Closure Strategy Presentation to the Senior Management Committee, November 25, 2013 (AGO Late-Filed Ex. 1, Tab L)[45]

Case Assessments, July, 2007). These documents all demonstrate that industry knowledge with respect to the environmental risks and implications of coal waste handling practices was more advanced at an earlier date than contended for by some of the Company's witnesses and that recommended best practices were, since at least the early 1980s, more sensitive to environmental concerns than represented by a bare minimum standard of regulatory compliance.

[45] Consideration of these critical internal policy documents is, by and large, missing from the discussion in the majority order. All of these documents pre-date the enactment of CAMA or the CCR rule. Even under the law as it existed during that time, the Company knew that regulatory closure would be required when the ash basins were retired. Representative is the following statement from an undated document likely authored in 2012 or 2013:

> Currently, federal regulatory programs do not specifically address the decommissioning and closure of ash basins; however, state regulations provide some options for closure framework. The

The intensified focus on closure of coal ash waste facilities in the 2000s was driven in large part by the aging of the Company's existing fleet of generation units and by the economics that increasingly favored conversion from coal to natural gas as a fuel. From this internal evidence it is clear that the Company was on notice throughout the decade of the 2000s and into the present decade, that the costs of removal of its waste ash storage and disposal facilities would affect, most likely very significantly, terminal net salvage values of its plants and thereby the amount of allowance it should seek to recover from ratepayers as depreciation expense. However, according to the testimony in this case, at no time during that period, including in its general rate cases in 2009, 2011, and 2013, did the Company include any provision for such costs of removal in its depreciation studies presented to the Commission. At least some portion of the costs the Company now seeks to recover in rates prospectively thus represents amounts the Company could have, and in my judgment prudently should have, recovered through depreciation expense in its existing and previously approved rates.

My view on this point is I believe in line with the Commission's decision in Order Granting Partial Rate Increase, Docket No. W-218, Sub 319 (November 3, 2011) (Aqua Order). In that proceeding, Aqua and the Public Staff disagreed as to the propriety of including in depreciation expense, and thus in rates, amounts for terminal net salvage value that would also incorporate costs of removal. The Company's witnesses pointed out that including these amounts in current depreciation expense would properly assign a portion of expected future expenses to those customers who were currently receiving the benefit of the utility plant while it was still in service. The Public Staff contended that such a practice would improperly require present customers to pay for future costs that might or might not actually be incurred, or might be different in amount at the time actually incurred. As to this difference of opinion, the Commission noted the applicant's testimony in the following summary:

> Witness Spanos[46] advocated utilizing the net salvage percentage for depreciation accrual rates consistently with the new practice[47] of recording the cost of removal as the most appropriate methodology. Therefore, according to witness Spanos, the cost of removal for each project will be charged to accumulated depreciation at the same time the Company accrues for the net salvage value in rates. Witness Spanos asserted that this consistent treatment properly assigns costs to those ratepayers receiving benefit for the asset while in service; this applies to all accounts.

> company is working closely with NCDENR to define a closure process that provides a framework for certainty in the absence of specific federal regulatory requirements.

AGO Late-Filed Ex. 1, Tab E (Filed on April 18, 2018.)

[46] This is the same witness Spanos who testified for the Company in the present case.

[47] Elsewhere in the Aqua Order, it is made clear that "new practice" means "new for this applicant," not new for the accounting profession. Prior to Aqua's 2011 rate case, Aqua North Carolina had not been computing net salvage values as part of depreciation expense.

Aqua Order at 70. Aqua Witness Spanos further explained that the entire cost of the asset, including costs of removal, should be recovered over the useful life of the asset and not recovered from customers after the asset's useful life had ended. Id.

In its order the Commission disagreed with the Public Staff's position and instead sided with the Company and its depreciation expert, witness Spanos, finding that:

> …utilizing the net salvage value percentage for depreciation accrual rates consistently with the new practice of recording the cost of removal is the most appropriate methodology. The Commission understands that using this methodology, the cost of removal for each project will be charged to accumulated depreciation at the same time the Company accrues for the net salvage in rates. *This treatment properly assigns costs to those ratepayers receiving benefit for the asset while in service and properly applies to all accounts.*

Id. at 72 (emphasis added).

In the present case, the Company's failure to seek recovery of waste ash storage and disposal costs as part of current depreciation expense in prior rates means that some portion of the properly allocable full cost of providing service to an earlier generation of customers will now be shifted to, and recovered from, future ratepayers. This is not in keeping with the sound policy and principles endorsed in the Aqua Order, nor do I believe it is consistent with the principles stated and endorsed by the Supreme Court in State ex rel. Utilities Commission v. Edmisten (Edmisten III), 291 N.C. 451, 232 S.E.2d 184 (1977). The Company is now seeking to recover from present and future ratepayers a cost that is attributable to service provided to ratepayers in prior periods. That cost is depreciation expense, more precisely that portion of depreciation expense representing the costs of removal upon final facility retirement that should be allocated among ratepayers over the entire useful life of the asset and not fall entirely upon those ratepayers at the time retirement occurs and funds are expended for decommissioning.

Some intervenors in this case have suggested that for any waste ash storage or disposal facilities associated with a generating plant, these costs of removal should have been collected through depreciation since the time the waste ash facility was first placed in service. On the present record, however, it is not possible to reconstruct this scenario today, and I have concluded that it is more reasonable to use as a beginning point the time the Company first knew or reasonably should have known, based on information available to it at the time, that it would incur substantial costs to close the waste facilities at the time of plant retirement and decommissioning. Based on the evidence recited earlier, this point in time was manifestly earlier than the date of enactment of CAMA or the adoption of the CCR Rule. I also conclude that it was at a point in time that predates the Company's general rate cases in 2009, 2011, and 2013, in none of which did it seek any provision for cost recovery of then-anticipated cost of removal of the waste ash storage and disposal facilities.[48]

The difficulty, of course, lies in determining how much cost has been improperly and imprudently shifted from past customers for service previously received, to present and future customers for service yet to be provided them. One device would be to look to the actions of the Company's affiliate, DEP, which requested and received approval in its 2013 general rate case to collect $10 million per year from customers for estimated costs of removal of its waste ash facilities. I do not find this option acceptable, however, since it ignores pertinent differences in the two companies' history of management of coal ash wastes and, more importantly, in the physical, environmental, and economic circumstances of their fleet of coal-fired plants and their associated waste ash facilities.

From the available evidence in the record I find that the cost estimates contained in two exhibits, Doss AGO Cross Ex. 1 (Ex. Vol. 12, pp. 818-839) titled "Plant Retirement Comprehensive Program Plan," and Atty. Gen. Late-Filed Exhibit 1, Tab J, titled "Plant Demolition and Retirement Presentation for the Executive Governance Committee," dated October 14, 2013, are the most appropriate to use for present purposes. The Plant Retirement Comprehensive Plan, dated October 31, 2012, sets forth the Company's then best estimates of plant decommissioning costs and, separately from general costs, costs for closure of waste ash storage and disposal facilities at the retired plants.[49] For the four coal-fired plants already retired or for which a near-term retirement date had been established - Buck, Dan River, Riverbend, and W.S. Lee – the estimated costs for closures of ash storage and disposal facilities totaled $115,538, 470. Interestingly, the estimate for other decommissioning tasks at these four retired plants totaled $32,323,875, confirming the statement in the 2004 EPRI plant decommissioning handbook that the costs of closing waste storage and disposal facilities would likely be the largest portion of plant decommissioning expense. The budgeted figures for closure of the waste ash facilities at the Buck, Dan River and Riverbend plants contained in the October, 2013, Plant Demolition and Retirement Presentation is $111,361,000. This total is less than the aggregate total in the 2012 comprehensive plant retirement plan, but it does not include any estimated costs for the waste facilities at the W.S. Lee Steam Station. Comparing

[48] There is nothing in this record to show that in setting the Company's prior rates the Commission was presented with any evidence concerning costs of removal for the waste ash impoundments apart from the general estimation of terminal net salvage values for the coal-fired generating plants contained in depreciation studies prepared by the Company's experts and relied upon by the Commission. For example, in Docket No. E-7 sub 1126, the Company's last general rate case before the instant proceeding, the depreciation study for each generating plant contained a negative allowance for terminal net salvage value for "Structures and Improvements," (Docket No. E-7, Sub 1126, Wiles Direct Ex. 3, p. 47), without further breakdown of the elements of cost entering into the calculation. Based on the evidence before it, the Commission had no ability to assess whether the Company had correctly or incorrectly identified and incorporated all the tasks that would be required upon plant retirement or whether it had identified and incorporated all the estimated costs of those necessary tasks. It was incumbent upon the Company to petition for and present evidence of the amounts needed to cover its known and expected expenses, including depreciation expense. E.g., New Jersey Power & Light Co. v. State Dep't. of Public Utilities, 15 N.J. 82, 92; 104 A.2d 1, 18 (1954)(cited with approval in Edmisten III).

[49] This plan is not a mere proposal; it carries all necessary approval signatures.

"apples to apples," the total estimate in the 2012 plan for the Buck, Dan River and Riverbend plants only was $93,272,969, meaning that the budget for closure activities at these three plants increased by $18,089,031 between 2012 and 2013. Both the 2012 and 2013 documents estimate expenditures over the same time period – 2013 through 2018. If the 2012 estimated closure budget for the W.S. Lee plant is added to the revised 2013 budget number for the Buck, Dan River and Riverbend plants, then the resulting total would be $133,626,501. As a point of comparison, this total is dramatically less than the $1,267,692,514, including in that total amounts for expected inflation, the Company now estimates it will spend over the next fifty years for closure of the waste ash units at these four plants. See Kerin Direct Ex. 11, p. 1.

Based on the available evidence, I find that the Company should have sought to collect in present and previously approved rates as costs of removal for the waste ash facilities at its four retired coal plants an amount not less than $133,626,501, and that its failure to do so was unreasonable and imprudent based on its knowledge at the time. Considering our obligation to be fair and reasonable both to ratepayers and to the Company and the requirement that we judge the Company based on information known to or reasonably available to it at the time of its conduct under examination, I conclude that the Company's present request in this rate case for recovery of amounts expended during 2015 through 2017 should be reduced by the amount of $133,626,501. Given the Company's long-standing and extensive knowledge of the types and magnitudes of costs it would have to incur, the certainty even before CAMA and the CCR Rule that it would be incurring them upon plant retirement, and its failure to seek to spread these costs equitably to all ratepayers who received benefit from the electricity service that caused such costs to be incurred, I believe this is a just and reasonable result. It avoids transferring to present and future ratepayers costs that should have been collected from ratepayers in prior periods.

Strictly applying the foregoing principles and analysis, it is unquestionably true that some amounts should also have been requested in depreciation rates prior to the present case for estimated costs of closure of waste ash facilities at the Company's operating plants, Allen, Belews Creek, Cliffside, and Marshall. However, in this record there is no evidence upon which a reasonable judgment could be made as to the additional amount attributable to these plants.[50] I note that the Company's cost recovery request for coal ash expenditures in 2015, 2016, and 2017 at these four plants largely consists of items that would be classified as inspection, maintenance, and repair activities at the existing waste impoundments, together with site assessment, planning and closure plan preparation activities. Actual costs for dewatering, consolidating, excavating, capping, and similar closure tasks remain for the future. There will be opportunity in the Company's

[50] Some closure estimates are provided in AGO Late-Filed Ex. 1, Tab L, p. 34 based on three different closure scenarios. These estimates are in a document dated November 25, 2013, after the filing of the Company's most recent general rate case application preceding the present one. I am unable to extract from this evidence, however, any reasonable estimate of amounts that the Company should have attempted to collect as costs of removal in prior rate cases. I consider the evidence more reliable in the case of the four retired plants because their retirement had been planned and information concerning closure of the ash impoundments had been studied and assembled over a period of years prior to the 2012 and 2013 estimates upon which I rely.

next general rate case to consider further the issue discussed here as it may relate to the Company's remaining coal-fired plants.

II. Rate of Return on Unamortized Coal Ash Waste Costs and "Mismanagement Penalty"

In this part I address my disagreement with the majority's decision to permit the Company to earn an investment return, equal to the weighted average cost of capital, on the deferred unamortized balance of its expenditures on closure of coal ash impoundments during the years 2015 through 2017 and its decision to impose a penalty for mismanagement of the ash basins in the amount of $70 million. Though these appear to be separate decisions, they are necessarily linked. The Commission first proposes to allow the Company to earn a return that I believe is, as to some of the costs involved, contrary to law and as to other portions of the costs, an abandonment of sound policy and practice and, on the record taken as a whole, an improper exercise of discretion. Having made this allowance, the Commission then reduces the total amount of the permitted return by $70 million and terms that reduction a "penalty" for mismanagement. Because there is no penalty if there is no allowed return on the unamortized balance of the waste ash costs, I focus my dissent on the first of these two decisions.

By way of opening I refer to and adopt in this case my rationale for denying a return on the unamortized balance of ash impoundment closure costs contained in my dissent in the DEP Rate Case Order. From the record assembled in this case, I have identified additional grounds to support the conclusion reached in my dissent in the prior case. On some points these additional grounds are based on matters and facts that may also have been pertinent to the decision in Docket No. E-2 sub 1142 but as to which the record was either silent or insufficiently complete to enable a judgment to be formed in that case.

A. SFAS 143, Ratemaking, and Property "Used and Useful"

The first issue I address is the irrelevance of SFAS 143 (now codified as ASC 410) to the issue at hand. The majority order has, I believe, conflated concepts of financial statement presentation with the classification of costs for ratemaking purposes. To avoid repetition I will not reprise the basic operation of SFAS 143 (now, which is reviewed at length in the Majority Order. Majority Order at 286-292. My focus here is on the majority's use of SFAS 143 to arrive at the conclusion that amounts expended by the Company for such tasks as dewatering surface impoundments, preparing ash for beneficiation or for disposal, excavating ash from its current storage location, transporting that ash to a new permanent disposal location onsite or offsite, and then monitoring and maintaining that permanent disposal site over an extended period of years have become "…property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service to be rendered to the public within the State…," making those expenditures eligible to earn a rate of return pursuant to G.S. 62-133(b)(4) and (b)(5). I do not believe SFAS 143 leads to such a result. More importantly, if it does produce such a result, that result is in conflict with the statutory language and structure of G.S. 62-133 and cannot be accepted.

Expenditures such as those catalogued in the preceding paragraph are not in themselves "property," although they are associated with "property," that being the waste ash impoundments. For purposes of SFAS 143 accounting treatment the waste ash impoundments are "long-lived tangible assets." For purposes of G.S. 62-133(b)(1) they either are now or formerly were "property used and useful in providing service."[51] The fact that they are associated with and related to "used and useful property" does not itself make them eligible for allowance of a return computed under G.S. 62-133(b)(4). If they are properly classified as "operating expenses" for purposes of G.S. 62-133(b)(3), then they are not eligible for a return. See, e.g., State ex rel. Utilities Commission v. Public Staff N.C. Utilities Commission, 333 N.C. 195, 424 S.E.2d 133 (1993) (reasonable operating expenses must have a nexus to property used and useful in providing service, but that nexus does not render operating expenses allowable under G.S. 62-133(b)(3) eligible for a return).

How, then, do expenses that would be considered "operating expenses" under G.S. 62-133(b)(3) become transformed by SFAS 143 into "property used and useful in providing service?" I believe the core of the majority's argument is contained in the following sentence: "Recognition of the [ARO] liability carries with it recognition of a corresponding asset – the capitalized cost of settling the liability, which under both GAAP and FERC rules is considered part of the property, plant and equipment for the assets that must be retired." Majority Order at 287. This statement requires careful attention, because it leads directly to what I believe is an error of law.

Under SFAS 143 when an asset retirement obligation is recognized and is recorded on the liability side of the balance sheet, of necessity there must be some corresponding and offsetting entry made on the asset side of the balance sheet. This is so because SFAS 143 is not structured such that the recognition of an asset retirement obligation, or "ARO," is meant to produce an immediate charge to retained earnings or to the equity account. The "asset side" adjustment is made by increasing the carrying cost of the long-lived asset to which the ARO relates by an amount equal to the amount of the recorded ARO liability. This increase in the balance sheet carrying value of the asset, called the "asset retirement cost" or "ARC," does not correspond to any actual increase in the value of the asset to whose book entry the ARC is added. Nothing at all has changed about the character, the qualities, the marketability, or the usefulness of the asset "…in providing the service to be rendered to the public." Likewise, nothing has changed about the "reasonable original cost of the public utility's property" embodied in that asset. The recording of the ARO liability and the capitalization of the ARC result from the change made by SFAS 143 in the timing of recognition of future cash outlays that are anticipated to be made at the time a long-lived asset is retired. The expenditures are not current outlays, but their recognition has been accelerated for financial statement presentation, and accelerated recognition must be offset by an entry on the asset side of the balance sheet.

[51] The difference between "now" and "formerly" is quite important, and is the subject of the discussion in Part II.B., as set forth hereafter. It is not a difference that is material, however, for purposes of the present argument in this section.

From this balance sheet entry, however, the majority order concludes that because the costs associated with the closure of waste ash impoundments are now capitalized on the balance sheet, the expenditures made for those closure activities "…whether they be denominated capital costs, O&M costs, general administration costs are nevertheless capitalized in connection with the establishment of the ARO…." Majority Order at 288. Restating the same point later, the majority says: " ...when properly accounted for in an ARO, the specific classification of costs is not determinative, because under GAAP and FERC guidance ARO costs are capitalized." Id. at 289. The analysis in the majority order boils down to this: because SFAS 143 requires that the carrying cost of the tangible asset with which an asset retirement obligation is associated must be increased for balance sheet purposes by the amount of the asset retirement obligation when that liability is recognized and recorded, the increase in the balance sheet carrying value of the long-lived tangible asset then becomes eligible for the recovery of a return under G.S. 62-133(b)(4) and (b)(5). This is error.[52]

There are multiple difficulties with this analysis as a matter of basic statutory construction of G.S. 62-133. It is, after all, that statute that controls the ratemaking treatment of costs – of all kinds and classification -- and the determination of which elements of cost are eligible to earn a return. Most immediately, G.S. 62-133(b)(1) requires that the Commission use as its basis or starting point, "the reasonable *original* cost of the public utility's property…." (emphasis added.) The amount of a balance sheet adjustment made to the carrying value of an asset when an asset retirement obligation is recognized in accord with SFAS 143 is manifestly not part of the "original cost" of that asset. Allowing the "original cost" to be adjusted or increased because of the operation of SFAS 143 involves, quite simply, impermissibly rewriting the statute. The concept of "original cost" in G.S. 62-133(b)(1) matters, since pursuant to G.S. 62-133(b)(4), a return is allowed only on the cost of plant that has been computed in accord with G.S. 62-133(b)(1).

A second difficulty arises from considering the overall structure of G.S. 62-133(b) in the context of accounting practice and procedure as it existed at the time the statute was enacted. G.S. 62-133(b)(1) and (b)(3) adopt and incorporate in their workings the concept of "depreciation." Accumulated depreciation reduces the amount computed under subsection (b)(1), which is the amount upon which a return may be earned, and depreciation is recovered as an operating expense, without return, under subsection (b)(3). As has already been discussed at length earlier, under traditional depreciation accounting the costs that will be incurred upon retirement of a long-lived asset ("costs of removal") are incorporated into depreciation expense as part of the calculation of terminal net salvage value. In this manner, they are recovered for ratemaking purposes as an

[52] It is also a reversal of the position taken in the Commission's August 8, 2003, Order in Docket No. E-7 sub 723. In that Order the Commission approved the Company's implementation of SFAS 143 accounting treatment for its obligations arising from decommissioning the irradiated portions of its nuclear plants and for environmental clean-up at its Belews Creek Steam Station. The Commission conditioned its approval on a number of specific qualifications and limitations, including "[t]hat no portion of the total ARO asset or liability shall be included in rate base for North Carolina retail accounting or ratemaking purposes."

operating expense pursuant to G.S. 62-133(b)(3), without a return, and not as "used and useful plant" entitled to a return.

SFAS 143 changes the time of recognition of costs of removal, in certain cases, for purposes of balance sheet presentation. It does this so that readers of financial statements may better understand expected future expenditures that will be associated with an asset.[53] Under SFAS 143 treatment the ARO and ARC entries substitute for and replace on the financial statement what had previously been shown on the financial statement as the cost of removal component of accumulated depreciation, reported as a "contra asset." Because these new entries are intended to be only a change for financial statement reporting purposes, they should be given the same treatment for ratemaking purposes as the cost of removal component of accumulated depreciation expense that they now replace. To afford any different treatment for ratemaking purposes would be, again, to allow the statutory structure and language of G.S. 62-133(b) to be amended by action of the Financial Accounting Standards Board. Whether or not such an amendment is desirable as a matter of policy, I do not believe it is within the power of the Commission to sanction it absent legislative action by the General Assembly. Because I differ with the majority and believe that under G.S. 62-133(b) the classification of costs – that is, whether they be property used and useful in providing service or whether they be operating expenses – is dispositive for purposes of eligibility to earn a rate of return, I dissent from the determination that the mere fact an item of expenditure has been reported on the financial statements as part of an asset retirement cost adjustment under SFAS 143 entitles the Company to earn a return on that expenditure.

Nor do I believe the Financial Accounting Standards Board contemplated the result arrived at by the majority here when it promulgated SFAS 143. Explaining the difference between SFAS 143 treatment and prior practice under SFAS 19, the official FASB publication promulgating the new standard explains:

> Under Statement 19, dismantlement and restoration costs were taken into account in determining amortization and depreciation rates. Consequently, many entities recognized asset retirement obligations as a contra-asset. Under this Statement, those obligations are recognized as a liability. Also, under Statement 19 the obligation was recognized over the useful life of the related asset. Under this Statement, the obligation is recognized when the liability is incurred.

With respect to the relationship between the new treatment of asset retirement obligations under SFAS 143 and the treatment of those same obligations for rate-regulated entities, the Statement explains in Paragraph 21:

> The capitalized amount of an asset retirement cost shall be included in the assessment of impairment of long-lived assets of a rate-regulated entity just as that cost is included in the assessment of impairment of long-lived assets of any other entity. FASB Statement No. 90, *Regulated Enterprises –*

[53] Statement of Financial Accounting Standards No. 143 (June 2001) pp. 4-5.

> *Accounting for Abandonments and Disallowances of Plant Costs,* applies to the asset retirement cost related to a long-lived asset of a rate-regulated entity that has been closed or abandoned.

Parsing through this language is not especially easy, but in plain English it says in substance the following: the capitalized amount of an ARO liability, i.e., the amount of the increase in the carrying cost of the long-lived asset on the asset side of the balance sheet, is to be given the same treatment as provided under SFAS 90 for a long-lived asset that has been closed. SFAS 90 is lengthy and detailed, but for present purposes the basic summary statement found in Paragraph 3 of the official statement suffices to make the point:

> When it becomes probable that an operating asset or an asset under construction will be abandoned, the cost of that asset shall be removed from construction work-in-process or plant-in-service. The enterprise shall determine whether recovery of any allowed cost is likely to be provided with (a) full return on investment during the period from the time when abandonment becomes probable to the time when recovery is completed or (b) partial or no return on investment during that period. *That determination should focus on the facts and circumstances related to the specific abandonment and should also consider the past practice and current policies of the applicable regulatory jurisdiction on abandonment situations.*[54]

Paragraph 20 of SFAS 143 makes essentially the same point:

> Many rate-regulated entities currently provide for the costs related to the retirement of certain long-lived assets in their financial statements and recover those amounts in rates charged to their customers. Some of those costs result from asset retirement obligations within the scope of this Statement; others result from costs that are not within the scope of this Statement. The amounts charged to customers for the costs related to the retirement of long-lived assets may differ from the period costs recognized in accordance with this Statement and, therefore, may result in a difference in the time of recognition of period costs for financial reporting and rate-making purposes. An additional recognition timing difference may exist when the costs related to the retirement of long-lived assets are included in amounts charged to customers but liabilities are not recognized in the financial statements. If the requirements of Statement 71 are met, a regulated entity shall also recognize a regulatory asset or liability for the differences in the timing of recognition of the period costs associated with asset retirement obligations for financial reporting pursuant to this Statement and rate-making purposes.

[54] Statement of Financial Accounting Standards No. 90 (December, 1986), pp. 5-6.

Two things are noteworthy about this Statement. First, it is an explicit recognition that the treatment of costs under SFAS 143 for financial statement reporting purposes may be different than the treatment of those costs for ratemaking purposes. Second, it expressly confirms that SFAS 71 continues to apply to the accounting treatment of such differences in treatment through the mechanism of regulatory assets and regulatory liabilities.[55]

The upshot of this is that under SFAS 143, SFAS 90 and SFAS 71, which must be read together, the capitalized amount of an asset retirement cost, that is, the increase in the carrying cost of the asset equal to the amount of the ARO liability, may or may not, if it becomes an allowed cost for recovery in rates, carry a return *depending on the policies and practices applicable in a particular regulatory jurisdiction.* I read from this no intention in SFAS 143 that for a rate-regulated entity the accounting treatment of an asset retirement obligation, including the capitalization of the amount in the carrying cost of the associated asset, is to supersede or modify either the law, policy, or practice of any jurisdiction with respect to what items of cost may earn a return.[56]

Finally, I note that FERC Order 631, adopting SFAS 143 principles for entities subject to FERC jurisdiction, likewise does not compel inclusion of the capitalized amount of the asset retirement obligation in rate base; quite the contrary. Order 631, adopted on April 9, 2003, amended Title 18 of the Code of Federal Regulations to add a new section 35.18(a) that reads in full:

> A public utility that files a rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books must provide a schedule, as part of the supporting work papers, identifying all cost components related to the asset retirement obligations that are included in the book balances of all accounts reflected in the cost of service computation supporting the proposed rates. *However, all cost components related to asset retirement obligations that would impact the calculation of rate base, such as electric plant and related accumulated depreciation and accumulated deferred income taxes, may not be reflected in rates and must be removed from the rate base calculation through a single adjustment.*

(emphasis added)

[55] It is, of course, the case that not all regulatory assets or liabilities carry with them an associated rate of return. Whether they do so or not is, once again, a function of the provisions of G.S. 62-133.

[56] In October 2002, the Edison Electric Institute and the American Gas Association issued an industry paper titled "Asset Retirement Obligations Implementation Issues." Speaking to the effect of SFAS 143 on ratemaking, the paper observes (p. 5): "Many utilities have included removal costs in depreciation rates or some other rate recovery mechanism. For ratemaking purposes, the collection of depreciation expense, including the salvage, and grow removal cost should remain intact. If customers have been paying for the cost of removal through rates, they may have a reasonable expectation that the utility will expend the costs to remove the asset at the end of its useful life."

The intent of this new rule is explained by FERC in Paragraph 62 of Order 631, which states: "To ensure that all rate base amounts related to asset retirement obligations can be identified and excluded from the rate base calculation in a rate change filing, the Commission adds §§ 35.18 and 154.315 [dealing with jurisdictional natural gas entities] to its rate change filing requirements," and later in the same paragraph repeats the point, stating: "…[T]he regulations require that all asset retirement obligations related rate base items be removed from the rate base computation through an adjustment."

I therefore disagree with the majority order and would find that classification of costs and expenses – either as "used and useful property" or as "reasonable operating expenses" -- *does indeed* matter for purposes of applying G.S. 62-133(b)(4) and (b)(5). SFAS 143 does not pre-empt that choice.

B. The Four Retired Plants and Their Ash Storage and Disposal Facilities

Coal-fired generating units at four of the Company's plants were retired and were in decommissioning status at the time this rate case was filed. These include Buck units 1 through 6 (retired in 2013)[57], Dan River units 1 through 3 (retired in 2012), Riverbend units 4 through 7 (retired in 2013) and W.S. Lee units 1 through 3 (retired in 2014), and these units had been removed from plant in service. Kerin Direct Ex. 4 (Ex. Vol. 16, Part 1, p. 9.) Except for the units at the W.S. Lee plant, to which CAMA does not in any event apply, the coal-fired units at all four plants were retired and decommissioning activities had commenced or were in planning stages before the enactment of CAMA; all units were retired before final adoption of the federal CCR Rule, and all were likewise retired before the entry of the Company's plea in the federal criminal cases. See Ex. Vol. 16, Part 3, pp. 175-308. None of these retired units and none of the waste ash storage and disposal units associated with them will be used to provide any future service to ratepayers of the Company. With respect to the costs for decommissioning and closure of the waste ash facilities at these four plants and independently of all other reasons for disallowance of a return discussed in this portion of my opinion, I believe the Supreme Court's decision in State ex rel. Utilities Comm'n v. Carolina Water Service, 335 N.C. 493, 439 S.E.2d (1994) (Carolina Water Service), prohibits allowing any return on deferred unamortized costs associated with the decommissioning and closure of the waste ash storage and disposal units at the Buck, Dan River, Riverbend and W.S. Lee plants. In the present case the costs requested for deferral and amortization for the waste coal ash facilities at these plants totals $ 392,837,165. Kerin Direct Ex. 10 (Ex. Vol. 16, Part 1, pp. 22-23).[58] For perspective, the total costs requested for deferral and amortization at all the Company's operating and retired plants totals $731,850,458, meaning that the costs associated with waste units at the retired plants comprise 53.68% of the total request. Id.[59]

[57] Buck units 1 and 2 had been retired some years earlier. Units 3 and 4 were retired in 2011 and units 5 and 6 were retired in 2013.

[58] The numbers provided by the Company in this exhibit are systemwide and do not reflect only the North Carolina retail portion.

[59] See the preceding footnote.

I am not persuaded by the majority's attempt to distinguish Carolina Water Service from the instant case. The majority attempts to diminish the holding of the case by observing that recovery of a return on retired plant was not "the major issue in the case" and that discussion of the issue occupied only two pages out of a lengthy opinion. Majority Order at fn. 64. This is pure makeweight. I submit that the holding was succinctly stated by the Court because the principle of law does not require an elaborate or extended analysis. It is next observed that the costs at issue were that portion of the original investment in the wastewater treatment plant that had not been recovered through depreciation and that in this case the costs the Company seeks to recover are new costs incurred in 2015 through 2017. Again, I believe the attempted distinction fails. As has already been discussed elsewhere in this dissenting opinion, the costs to close the waste storage and disposal units at the four retired plants are properly costs of removal to be recovered through depreciation rates as an element of terminal net salvage value. The *outlays or expenditures* for these costs may have been made in 2015 through 2017, but the *costs* – costs of removal, or depreciation expense -- were incurred and are properly allocable over the operating life of the waste facilities. In the present case, some of the coal-fired plants and associated waste ash facilities were retired earlier than their anticipated useful lives (e.g., Buck and Riverbend); others were retired at the end of their expected lives (e.g., Dan River). What matters under Carolina Water Service is that the plants and their associated waste ash facilities were not at the time this rate case was filed and never would be in service again.[60] They were not at the time of this case "property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service to be rendered to the public within this State…." G.S. 62-133(b)(1).

An argument has been advanced that these retired ash basins remain "used and useful" because they provide environmentally safe permanent disposal of waste ash for the protection of, among others, the Company's ratepayers. I consider this argument creative fiction. These basins contain ash residue from the burning of coal to provide electricity service to ratepayers before the retirement of the generating plants which they serviced. A fair reading of G.S 62-133(b) is to the effect that property "used and useful" upon which an investment return may be earned must be committed to the provision of utility services to present and future customers, not a prior generation of customers. I do not dispute that the costs of completing decommissioning and closure of the basins and thereafter of maintaining and monitoring them are recoverable as reasonable expenses of operation pursuant to G.S. 62-133(b)(3), but it strains common sense that they are in

[60] In Footnote 64 of the Majority Order, an effort is made to characterize the waste surface impoundments as a "class" of property for purposes of determining such matters as useful life, depreciation, and retirement from service, as if they were akin to such items as poles, conductors, and transformers. There is simply no support in the record for this attempt. The overwhelming weight of the evidence demonstrates that the ash basins were each treated and dealt with by the Company as individual units associated with their respective generating plants. The attempt to argue that they are "mass" or "class" assets on this record stands on no better ground than would an attempt to argue that all the Company's coal-fired generating units taken together constitute a single "class" for purposes of ratemaking treatment.

any respect providing the “service” to present and future customers that is contemplated by G.S. 62-133(b)(1). Moreover, I note that to the extent this argument has merit, which I do not believe it has, *even by its own terms* it can apply only to newly constructed landfills or other waste disposal units that will provide permanent storage for waste ash as part of the closure of the existing waste storage facilities. For example, surface impoundments, such as the primary and secondary ash basins at Dan River or the primary and secondary ash basins at Riverbend, or the three ash basins at Buck, all of whose waste contents will first be excavated and then removed from them before the basins are closed cannot be said to be providing thereafter any service to present or future customers.

I have also considered whether it may be the case that the ash basins at the retired generating plants may remain in use for purposes other than temporary storage of coal combustion wastes, but the record does not answer this question. Some of the Company’s waste impoundments were used to treat other low-volume waste streams, from plant processes other than burning coal for the generation of electricity. During the hearing on the application the Company was asked to provide a late-filed exhibit showing the date use of each of the surface impoundments for these other waste streams ceased. From the exhibit filed by the Company an answer to this question of other use cannot be derived.[61] With the exception of the inactive ash basin at the W.S. Lee plant, the 1977 inactive ash basin at the Cliffside plant, and the primary ash basin at the Dan River plant the late-filed exhibit reported that all other ash basins at the four retired plants (Buck, Dan River, Riverbend, and W.S. Lee) were still receiving process wastewater “and/or” “stormwater (considering gravity flow as stormwater inflow)”. Because the exhibit included not only the four retired plants but the four operating coal-fired plants and because it was not provided until after the close of the hearing, it is impossible to unpack this “and/or” phrase as to any individual waste impoundment. Even if it were assumed that stormwater (and groundwater, i.e., gravity flows) continues to flow into the retired ash basins, this is a function of the fact that the impoundments have not been finally covered or capped and that closure is not yet complete. It is not an indication that the impoundments will continue to be “used and useful” into the future as ongoing “stormwater treatment units.” Accordingly, I find that the Company’s Kerin Direct Ex. 5 (Ex. Vol. 16, Part 1, p. 10) establishes the dates of final use of the ash basins at the Buck (2013), Dan River (2012), Riverbend (2014), and W.S. Lee (2014) plants.[62] Those dates all precede the filing of this case.

[61] Pursuant to a request I made on the record during the evidentiary hearing, the Company, through its counsel, filed this late-filed exhibit on April 2, 2018, containing a spreadsheet containing the information discussed here.

[62] These dates are identified on the exhibit as dates basins were “closed,” but witness Kerin explained that this does not refer to closure for regulatory purposes but the date the impoundment ceased receiving wastes for treatment and storage. Tr. Vol. 16, pp. 43-47.

C. All Plants – Separating Sheep from Goats

The argument in the prior section applies only to those waste ash facilities at the coal-fired plants that were retired prior to 2015.[63] In this section I address issues that arise in the case of all plants, operating and retired. Proper characterization of the costs the Company is seeking to recover for ash basin closure activities at its plants is essential for application of the ratemaking provisions in G.S. 62-133(b). On the record in this case that is a difficult, if not in part impossible, assignment. Part of the difficulty is a function of the different stages in which the closure process now stands at each of its plants and for each of the waste ash units and the different rates at which closure activities are progressing. Another part is the difficulty of reconciling the listing of the tasks for which cost recovery is sought in this case with historical documentation of ash basin closure tasks already undertaken by the Company in periods prior to 2015, the first year for which cost recovery is being requested in this case. Yet a third portion of the difficulty is the opaqueness of the task descriptions in the pertinent exhibits and evidentiary submissions themselves.

Kerin Direct Exhibits 10 (Ex. Vol. 16, Part 1, pp. 22-23) and 11 (Revised Kerin Ex. 11, filed by DEC on March 22, 2018) are the core exhibits summarizing the request for cost recovery in this case. For each of the retired and operating plants, Exhibit 11 sets out a summary of categories of expenditures, both actual for 2015, 2016 and 2017, and forecast for later years. I use the portion of Exhibit 11 that speaks to the Allen plant, an operating plant, for illustration. The categories fall into two groups. The first group includes: (1) mobilization and site preparation, (2) site infrastructure, (3) water treatment & management, (4) ash processing, (5) construct landfill & cap-in-place, (6) site restoration, demobilization, closing, (7) engineering closure plans, (8) a category designated as "Duke Cost," (9) site maintenance landfill, etc., and (10) contingency. These ten categories of costs are grouped together in a summary subtotal titled "Basin Closure." A second group of items consists of a group of eight other categories of costs, including (1) CCP[64] basin support projects, (2) CCP oversight & LRP, (3) CCP inspections and maintenance, (4) CCP engineering, (5) EHS, (6) post-closure maintenance, (7) previous landfill ARO cash flows, and (8) inflation impacts.

[63] The position I have taken with respect to the closed generating units could be extended to include the former ash impoundments at the four operating coal-fired plants – Allen, Belews Creek, Cliffside, and Marshall -- that were removed from service long in the past. These would include the 1957 ash impoundment at the Allen plant, which was closed in 1973 and the 1957 and 1970 ash basins at the Cliffside plant, which were closed in 1977 and 1980, respectively. This is in fact the position I adopted in dissent in the DEP Rate Case Order. The Company advised, in response to a question on the point, that it could not present a separate accounting for closed or inactive impoundments apart from the closure costs incurred and expected to be incurred for the remaining active impoundments. Tr. Vol. 16, p. 52; DEC Response to Commission Request Regarding ARO, filed April 6, 2018. While witness Garrett was able to obtain some separate data for the inactive ash basin and the borrow area at the retired W.S. Lee plant, the same level of detail is not present in the record for the retired basins at any of the operating plants.

[64] "CCP" is shorthand reference for "coal combustion products," otherwise known as wastes left from burning coal.

Page 8 of Kerin Direct Exhibit 11 contains footnotes for these categories, but it provides only marginally more information than the titles of the categories themselves suggest. A number of the categories can be understood from the testimony of witness Kerin or other witnesses in the case. For example, "CCP inspections and maintenance" appears to refer to ongoing maintenance activities relative to the surface impoundments, including such tasks as maintaining the integrity of dikes and dams, preventing vegetation encroachment, maintaining risers and discharge piping, and similar. "EHS" appears to refer to an allocation of the costs for the Company's general Environmental Health and Safety department, but the footnote suggests that it also includes "well installation, well sampling (groundwater monitoring), bottled water and permanent water supplies provided to nearby residents." "Construct landfill & cap-in-place" is fairly straightforward; it captures the costs to construct a new permitted landfill or to cap-in-place an existing unit. The categories titled "water treatment and management" and "ash processing," based on the testimony of witnesses Kerin, Garrett, Moore, and Wells, likely involves dewatering of ash in an impoundment, consolidating the ash and preparing it for removal, excavation of the ash, and transport to another location for final disposal. The category "inflation impacts" shows the expected increase in costs for tasks that will not be undertaken until later years in the period covered by the exhibit (2015 through 2057). Other categories are more opaque. For example, how do the tasks embraced within the category "CCP Basin Support Projects" differ from those in such categories as "CCP Oversight and LRP," or "CCP Engineering," or for that matter, what is included in "CCP Engineering" that is not included in "Engineering Closure Plans"? Finally, other categories, most notably the one titled "Duke Cost" remain a complete mystery; all that can be said with any certainty is that it represents costs that do not fall within one of the other enumerated categories.

I am mindful of the principle that we take the amounts recorded in the Company's books as they are given and do not look behind them unless a specific challenge is made to some item of expense or revenue.[65] The issue here presented, though, does not involve questioning the amounts reflected on Kerin Direct Exhibits 10 and 11 but rather deciding, for ratemaking purposes, which of those amounts represent investments for which the Company may earn a return and, on the other hand, those which are in the nature of expenses of operation and maintenance. Even within the first grouping of expenditure categories, those summarized as "Basin Closure," proper characterization is somewhat difficult. "Water treatment and Management" appears to refer to the process of decanting standing water and dewatering the ash in the basin. "Ash Processing" appears to refer to consolidation and stacking of the dewatered ash in order to reduce the area footprint that will require capping and vegetation or, if the ash is to be excavated, consolidating it for more efficient transport, or perhaps treating it for purposes of beneficiation.

[65] Agreeing with the Company's proffer, Public Staff witness Moore testified that based on his review of the costs incurred in 2015, 2016 and 2017 for the ash basins at the four operating plants -- Allen, Cliffside, Belews Creek, and Marshall -- were reasonable and prudent, and I am not contesting this judgment. Again, the issue is how those costs should be characterized for ratemaking purposes.

From the available evidence I conclude that the costs for which recovery is sought in this case include a significant mixture of costs that are correctly characterized as operating and maintenance expense, and another portion that might be considered investment in capital assets required for basin closure. In the case of the Allen plant, which I have used as an illustration, most of the expenditures for the years 2015, 2016 and 2017 are recorded in categories that appear more appropriately considered operating and maintenance expenses, especially since the ash basin at the Allen plant remains active and actual closure has not yet commenced. For example, during the period 2015 through 2017, none of the costs incurred at the Allen plant have been for such activities as “mobilization and site preparation,” “site infrastructure,” “ash processing,” “construct landfill & cap-in-place” or “site restoration, demobilization and closing,” which are categories that it might be argued are capital in nature and potentially eligible for a return. For 2015 and 2016, of the total requested cost recovery of $32,663,754, some $28,908,681 is recorded in the categories “EHS,” “CCP oversight and long range planning,” and “CCP basin support projects.” Only $3,755,073 is recorded in the large subgroup of categories headed “Basin Closure,” and of this total $2,457,590 (or 65.45% of the total) falls within the mysterious category labelled “Duke Cost.”[66]

The problem can also be illustrated by a different example. For the period 2015 through 2017, the period for which cost recovery or deferral and amortization are sought in this case, total costs incurred for closure activities at the Dan River Steam Station were $143,237,755, and total costs incurred for closure activities at the Riverbend Steam Station were $220,273,249. Kerin Direct Ex. 10 (Ex. Vol. 16, Part 1, pp. 22-23.)[67] These are the two sites ranked high priority under CAMA, and together these two plants account for 49.67% -- just under one-half -- of the Company’s total expenditures on all its waste ash storage and disposal facilities during the period. Based on the information that can be extracted from Revised Kerin Direct Ex. 11 (filed by DEC on March 22, 2018), interpreted in light of witness Kerin’s testimony, the testimony of witnesses Garrett and Moore, and documentary exhibits, the principal activities conducted at these two plants included excavation, transport and offsite disposal of ash fill area 1 at the Dan River plant, dewatering ash in the primary and secondary surface impoundments at Dan River, excavation and transport of ash from the ash stack at the Riverbend plant to Roanoke Cement Company and the Brickhaven mine, dewatering the primary and secondary ash basins at the Riverbend plant, and beginning excavation and transport of ash from the primary and secondary ash basins at the Riverbend plant for offsite disposal. I do not believe these activities can be under any reasonable interpretation of G.S. 62-133(b)(1) considered investments in plant or facilities used or useful to provide electric service to present and future customers. [68] They are under any common understanding of the terms, expenses of operating and maintaining the (retired) coal-fired generating plants.

[66] In this example I do not include the figures for 2017, since they are projected numbers on Kerin Ex. 11.

[67] The data in this exhibit were presented on a systemwide basis and do not represent the North Carolina retail allocation. For present purposes, however, that point is not material.

[68] The Company plainly knows how to characterize an expenditure as “capital” versus “operating.” On Kerin Direct Ex. 11, the costs to purchase the equipment necessary for preparing ash excavated from

I use this second example because the elements of cost involved are fairly straightforward and are, on this record, a very large proportion of the total expenditures for which recovery is being allowed by way of deferral and amortization. The point of all the foregoing is that the assumption made in the majority order that *all* of the costs incurred and yet to be incurred are "assets" or are "investments" that are "used and useful" simply cannot withstand a more granular examination and consideration of the specific items of cost and their nature. I believe it is error to conclude that simply because the costs incurred by the Company relate, in some manner, to present or former waste surface impoundments, they therefore constitute expenditures or investments for which a return is authorized by G.S. 162-133(b)(1). Sorting out those costs that represent an investment in "used and useful" plant and equipment from costs that represent either ordinary or extraordinary expenses of operation requires a plant-by-plant, waste unit-by-waste-unit, task-by-task inquiry and evaluation.[69] This the Majority Order does not do, instead lumping all tasks, all waste units, all time periods, and all plants together and allowing a return on the expenditures without further qualification, except only the reduction of that return by $70 million. I further believe that this outcome is largely the result of the erroneous determination that it is unnecessary to engage any such exercise because of the Company's adoption of SFAS 143 accounting for its coal ash expenditures. the Even if the Commission has discretionary authority to allow a return on the unamortized portion of the amounts expended from 2015 through 2017, I do not believe its exercise of that discretion in such an undifferentiated and summary fashion is proper.

D. Working Capital …. or Not?

As did its affiliate in the DEP Rate Case, the Company here attempts to argue that its expenditures for closure of the waste ash impoundments have been financed from shareholder funds provided for working capital and that they are therefore eligible for a return under the holding in State ex rel. Utilities Comm'n v. Virginia Electric & Power Co., 285 N.C. 398, 206 S.E.2d 283 (1974) (VEPCO). I note that the Company's presentation of evidence on this point differs in no material way from the presentation made by its affiliate in the DEP Rate Case, and I find it no more persuasive here than in that proceeding. The calculation of working capital set forth in witness Doss Direct Ex. 2 (Ex. Vol. 12, p. 786) contains no amounts designated as needed for additional working capital due to coal ash costs, and the Company's position I believe rests on nothing more than an *ipse dixit*.

In this case I find in the evidence an additional reason for rejecting the Company's position. As the Court made clear in VEPCO, not all funds that are functionally used as

the impoundments at the Buck Steam Station for beneficial reuse is specifically denominated in a separate category titled "Capex – Equipment and Facility Cost."

[69] This is not an impossible task. It is one the Company knows very well how to perform. For example, in its 2008 Coal Combustion Products Ten-Year Plan, Kerin Public Staff Ex. 2, Vol. 16, Part 1, p. 47 and *passim*, the Company prepared elaborate budgets for planned expenditures for its coal ash storage and disposal facilities, classifying those expenditures as either "Capital," "O&M," or "Risk," the latter term possibly referring to the "risk" that they might not be recoverable in rates.

working capital are investor provided funds on which a return may be allowed; funds provided by ratepayers to cover anticipated expenditures not yet incurred may be used by the Company in the interim as working capital, and such funds are not eligible for a return. Id. at 415, 206 S.E.2d at 293.

Due to the enactment of the Federal Tax Cuts and Jobs Act of 2017 the evidence shows that the Company has collected from ratepayers an amount presently estimated to be in the order of $953 million in unprotected EDIT that it will not now be required to pay to the federal government in taxes. (Revised McManeus Workpapers, Schedule 1-4, Line 2, Column (b), and Schedule 1-5, Line 8, filed by DEC on April 19, 2018.) This amount must now be returned to ratepayers. In the Matter of Tax Reform Act of 1986, Docket No. M-100, Sub 113, 82 P.U.R.4th 234, 234-35 (Oct. 23, 1986), aff'd, State ex. rel. Utilities Comm'n v. Nantahala, 326 N.C. 190, 197, 388 S.E.2d 118, 122 (1990). In the interim, these funds represent precisely the type of "ratepayer provided working capital" about which the VEPCO court spoke.

The final number of such excess deferred income taxes will be refined as the Company does further analysis of the actual effect of the new tax legislation. Because this development occurred after the test year for this case, after the rate case was filed, and on the eve of the hearings on the Company's application, the Commission has concluded that disposition of this excess amount collected from ratepayers in anticipation of taxes that will now not be paid should be deferred until the Company's next general rate case and placed in a regulatory liability account in the interim. I support this disposition. For present purposes, however, the important fact is that the Company will have the use of these ratepayer provided funds as "working capital" until such time as they are returned to ratepayers in the manner provided in the Company's next general rate case. The final amount, even after refinement, will be substantial, and I find it impossible on this record to conclude that in order to finance its costs to close its waste coal ash impoundments between now and the time of its next general rate case the Company either has been or will be, in the near term, using shareholder provided funds instead of or to the exclusion of ratepayer funds such as the amount represented by this regulatory liability item.

E. A Final Matter of Policy

Ash wastes are a residue from the burning of coal to generate electricity. Supplying electricity is the service for which the Company is entitled to compensation, and the investments it makes in plant and facilities in order to supply that service are the capital assets on which it is entitled to earn a return. There is no dispute that the cost of the coal burned is an operating expense incurred in order to deploy those capital assets to provide electric service. It stands this paradigm on its head to allow the Company to treat the residue from this fuel as a new opportunity for capital investment and for profit-making. The fuel itself has real value for the provision of a desired service, electricity; surely the unwanted residue, except when committed to beneficial reuse, has no such value. Yet under the majority's analysis, the residue has now become of greater profit-making value to the Company than the underlying fuel itself. We are in the waning years of the Company's use of coal as a fuel, but even so the Allen, Marshall, and Cliffside coal-burning units will continue to consume prodigious quantities of coal for over a decade to come. The cost of that coal will be reliably recovered, without profit, in the Company's general rates and through the fuel adjustment rider. What the majority does today, however, creates an undesirable incentive with respect to the use of that coal. Different coals burn with different degrees of efficiency and generate different quantities and qualities of waste as per unit of coal burned. Is there now to be an opportunity for earning an increased profit by purchasing lower quality coal or coal that leaves more residue or residue more expensive to manage, thereby generating higher disposal costs when the ash basins at the still-operating plants are finally retired? These costs will form the basis upon which additional profit may be earned. This is an unacceptable and even absurd result, and I do not suggest that the Company would intentionally pursue such a course. However, this "thought exercise" illustrates the type of error into which I believe the majority has fallen by allowing recovery of a return on the deferred costs of permanently disposing of the waste ash. I believe the General Assembly in Chapter 62 intended to provide an opportunity for companies to earn a return on the provision of a valuable service – electricity. It did not intend to establish that scheme in order to encourage investment in waste management enterprises.

In summary and for all the foregoing reasons I find that on the present record the deferred portion of allowed costs attributable to closure of the waste ash storage and disposal facilities are ineligible for allowance of a rate of return. It is not necessary for me to say anything further about the "mismanagement penalty" assessed in the Majority Order because there is nothing to which that "penalty" attaches.

III. Increase in Basic Facilities Charge (BFC) and its Applicability Only to the Residential Class of Ratepayers

The majority's decision to permit an increase in the fixed monthly billing charge for residential rate classes, but not for any of the other customer rate classifications, I consider one of the more peculiar aspects of the decision, and I dissent from that portion of the findings and order that authorizes the increase. While in the final outcome the Commission has determined that the Company's revenue requirement should be reduced, and I concur generally in that result, although based on issues discussed in this dissent, I would find and am of the opinion that the revenue requirement should be lower than that determined by the Commission majority. Despite the evidence and issues addressed elsewhere in this dissenting opinion which support a further reduced revenue requirement, the majority approves an increase in the fixed monthly charge affecting only the residential customers.

The majority does not support its determination with any findings or evidence showing that the Company's fixed costs to serve residential customers has increased over what is supported by the revenues upon which the Company's present rates are based. It does not make findings or point to any evidence that the fixed costs to serve residential customers have increased relative to costs of service for non-residential customers. While not granting the full amount of increase requested by the Company for the residential rate class, the majority rejects altogether the Company's request for an increase in the fixed monthly charges applicable to non-residential rate classes, without offering a compelling reason, nor a reason which is supported by the record in this case, for such different treatment. I acknowledge that these observations are all about cost of service and that the matter of setting the fixed monthly component of rates is a matter of rate design. However, if there is no demonstrated need for additional revenue to be provided from residential ratepayers, other justifications for the increase must be found. Moreover, to support such a difference in treatment between the residential and non-residential classes, there must be justifications peculiar to the residential rate classes and not applicable to the non-residential rate classes. I believe the majority's justifications, to the extent they are articulated at all, are without basis in the record.

The only grounds of justification for the increase in the residential fixed charge portion of the residential rates to be gleaned from the majority order are 1) the unsupported easing of subsidization between members of the residential class and 2) the acceptance of the Company's assertion that, based on the "minimum system" method for the allocation of the customer portion of distribution plant costs, the present residential monthly fixed charge is lower than the actual fixed charge caused by the residential class of customers. Dealing with the grounds separately, the majority's subsidization justification for increasing the fixed monthly charge for residential customers is set forth in a single sentence:

> The increase in these schedules minimizes subsidization and provides more appropriate price signals to customers in the rate class, while also moderating the impact of such increase on low-income customers to the extent that they are high-usage customers such as those residing in poorly insulated manufactured homes.

Majority Order at 112. That is it; all else is based on alleged cost causation, i.e., that the current fixed charge does not accurately reflect the Company's fixed costs of serving residential customers. The "subsidization" referred to here is alleged subsidization by high usage customers of the low usage customers, the latter category including, among others, customers who have aggressively implemented energy efficient measures and may even be self-generating a portion of their own electricity needs. A contrast is drawn between these low usage customers and the high usage customers, such as "those residing in poorly insulated manufactured homes," who are allegedly subsidizing the low use customers through energy charges artificially inflated by a fixed charge that is too low. The difficulty with this picture is that it is conclusory and simply without evidentiary support in the record. Indeed, the only evidence offered by any party in an attempt to characterize who are the "low users" and who are the "high users" was offered by NC Justice Center, et al. witness Howat, whose evidence was to the effect that the population of low-use customers tends to have a higher proportion of low-income, elderly, and African-American ratepayers; not that low income customers reside in poorly insulated homes or are high energy users as asserted by the majority. It is not necessary to decide for the present whether Howat's evidence is correct, only to point out that the majority has no evidence to support any contrary picture or the majority's stated (stereotypical) presumption that low income customers are high energy users subsidizing low energy users.[70]

This then leaves the majority with only its "cost causation" justification for the increase in the residential fixed charge. As I have already noted, the Commission in prior rate orders has recognized that cost allocation and rate design are separate topics, and the parties continue to pay homage, at least in principle, to this distinction. Nonetheless, with respect to setting the fixed component of monthly customer bills, a matter of rate design, it is apparent that the positions of the contending parties are largely determined by their views concerning the propriety of using the so-called minimum system method for allocating the customer portion of distribution plant costs. In past rate cases the Commission has permitted the Company to use the minimum system method for purposes of deriving the customer portion of embedded distribution system costs, but it has expressly stated that the results yielded by that method do not and should not dictate the level of the per customer fixed monthly charge. See, e.g., Order Granting Partial Increase in Rates and Charges, Docket No. E-2, Sub 526, at pp. 29-30. Moreover, there are other considerations, aside from costs, that go into rate design, including setting the fixed charge portion of the rate. See DEP Rate Case Order at 107-08, 114 (acknowledging that factors other than cost of service are appropriate to consider and balance in rate design). In the present case the majority takes the further positive step of directing the Public Staff to initiate discussions with the regulated electric utilities to explore in greater depth the use of the minimum system method and alternative methods for allocating distribution system costs and to submit a report to the Commission by March 31, 2019.[71]

For myself, while I will consider the report and any other evidence that may be properly introduced, I am concerned that the time has come or may have come to divorce, explicitly and completely, the setting of the fixed monthly charge from any association with the minimum system methodology used for allocating embedded distribution system costs. It may be that the minimum system method should be rejected entirely as both a tool for cost allocation and, as a necessary consequence, as an indirect determinant of the per customer fixed monthly charge.[72] The reasons for abandoning use of the minimum system method have been ably briefed by several of the intervenors, including

[70] Moreover, if the majority's expressed concerns about subsidization are legitimate, the Company's request in this general rate case to increase the fixed charge portion of the rate applicable to the non-residential classes would indicate that the current non-residential rates are not properly balanced between fixed charges and demand charges, and the Commission should have the same interclass subsidization concerns with respect to non-residential customers. However, the majority discriminatorily disregards, without explanation or justification, the issue of subsidy for all but the residential class of customers and does not impose any fixed charge increase on nonresidential customers to ease the impact of alleged subsidization.

[71] Part of the majority's rationale for taking this step relies on language taken from my dissent in the DEP Rate Case. Based on continued study of the issue since that time and the additional evidence taken in this case, my position has now become more firm on the subject, especially in light of the result in this case concerning the residential fixed monthly charge.

[72] I would do this for all customer classes, not just the residential rate classes.

NCSEA and the NC Justice Center, et al., and are powerfully supported by the testimony of witnesses Barnes and Wallach. The Company's defense of the minimum system method rests almost entirely on history and custom, supplemented by the fact that the minimum system is one among several recognized methods for allocating the embedded costs of distribution system plant and facilities among rate classes. Tr. Vol. 19, pp.34-35.

The method has been persuasively condemned on conceptual grounds, one of the more notable critics being Professor Bonbright, who in his 1961 treatise observed:

> [T]he really controversial aspect of customer-cost imputation arises because of the cost analyst's frequent practice of including, not just those costs that can be definitely earmarked as incurred for the benefit of specific customers but also a substantial fraction of the annual maintenance and capital costs of the secondary (low-voltage) distribution system – a fraction equal to the estimated annual costs of a hypothetical system of minimum capacity. This minimum capacity is sometimes determined by the smallest sizes of conductors deemed adequate to maintain voltage and to keep from falling of their own weight. In any case, the annual costs of this phantom, minimum-sized distribution system are treated as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they therefore vary indirectly with the number of customers. What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Indeed, if the company's entire service area stays fixed, an increase in the number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.

James C. Bonbright, Principles of Public Utility Rates, Columbia University Press, 347-348 (1961).

This objection is reinforced by the fact that the methodology's stated purpose -- to allocate those embedded distribution system costs that are a direct function of the number of customers served by the distribution system -- is one that is difficult to realize in practice with any reasonable degree of faithfulness to the nominal principle behind the method. I find the report[73] prepared by Frederick Weston (The Regulatory Assistance Project), cited by NCSEA witness Barnes, to be most informative on this subject. Weston notes in his Executive Summary that "The distribution network is no longer the seemingly static

[73] F. Weston, et al., *Charges for Distribution Service: Issues in Rate Design*, Regulatory Assistance Project (2000), available at http://pubs.narus.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

monopoly that it once was. The policies that regulators adopt should be devised with an eye to competitive service provision, to encourage innovative and environmentally sustainable energy use. They should not shortsightedly protect a status quo that, over the coming decades, will not be well-suited to the economy it serves."[74] Further, Weston states that "There is broad agreement in the literature that distribution investment is causally related to peak demand. Numbers of customers on the system and energy needs are also seen to drive costs, but there is less of a consensus on these points or on their implications for rate design. In addition, not all jurisdictions employ the same methods for analyzing the various cost components, and there is of course a wide range of views on their nature; marginal, embedded, fixed, variable, joint, common, etc. and thus on how they should be recovered in rates."[75]

The Company implicitly acknowledges this problem when it concedes that its actual application of the minimum system concept is a modification or variation of the pure principle. See Tr. Vol. 19, pp. 38-39. I do not agree with the majority's opinion that the minimum system analysis employed by the Company is not flawed in a way that makes it inappropriate for cost allocation in this proceeding. Rather, the critiques offered by NCSEA and NC Justice Center, et al., in their post-hearing briefs, and the testimony of witness Barnes, in particular, are compelling. In its post-hearing Brief, NCSEA states that "the minimum system analysis is flawed." See NCSEA's Post-Hearing Brief, p. 37. NCSEA states that the minimum system methodology "assumes that some costs of the shared distribution system are effectively incurred solely for the purpose of connecting each customer and that these costs should therefore be classified as customer-related." Tr. Vol. 20, pp. 75-76. In effect, the system methodology "double counts" demand-related costs because a minimum system is still capable of serving some level of demand. Id. at 76.

Furthermore, NCSEA states that the Company's modified minimum system methodology does not examine actual costs, but rather defines costs for specified components and extrapolates those costs across the Company's system. Id. at 86. In the case of poles and conductors, this results in more items being included in the minimum system study than are actually on the Company's system and results in a negative assignment of these components in the demand charge. Id. at 87. Further, NCSEA states that the Company's modified minimum system methodology contains flaws in its analysis of poles and structures, overhead conductors, line transformers, and service drops. Id. at 90-94.

According to witness Barnes, DEC effectively classifies all shared secondary and primary poles in FERC Account 364 (as well as conductors in FERC Account 365) as customer-related. This is visible in the Company's COSS in the form of negative values for demand-related plant in service for FERC Accounts 364 and 365.[76] The negative

[74] Id. at 5.

[75] Id. at 28.

[76] DEC Form E-1, Item 45D, p. 5.

values arise because the Company's calculated minimum system is larger than the actual FERC Account balance after removing direct assignments, which necessitates an adjustment. The true-up adjustment effectively results in a demand-related component of zero and a customer-related component of 100%. Similar differences are evident for other distribution Accounts, contributing to a wide range of estimates of residential customer unit costs. Tr. Vol. 20, pp. 82-83. These detailed objections to the Company's practical application of the method in practice are not effectively rebutted by the Company, and this in itself is some confirmation of a large degree of subjectivity in how the method is applied to a real world distribution system.

If the minimum system method is inappropriate for assignment of the customer portion of distribution system costs among the several customer classes, then what is to replace it? Here I suggest that a defensible method, and the one that is most widely used by other regulatory authorities, is perhaps to use a per customer allocator only for those costs directly attributable to the addition of another customer to the distribution grid – the cost of the customer meter, the service drop, and any other facilities uniquely attributable to a specific customer. All other distribution system costs, including poles, transformers, and conductors, would use a demand allocator entirely. This is the so-called "basic customer method" well-recognized and widely used as an alternative to fixed charges that are designed to reflect output from the minimum system method of cost allocation. The Commission's Order acknowledges this by recognizing the testimony of witness Barnes and specific reference to Mr. Weston's report, which states that "There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states."[77] Tr. Vol. 20, p. 79.

Shared distribution plant and facilities, whose cost would be assigned using a demand allocator, are those actually installed by the Company to meet real world expected demand and maintain service reliability. Put differently, excluding only the marginal costs directly attributable to the addition of another customer, the system whose costs must be recovered is not sized to meet some "phantom" level of demand but instead is sized to meet actual historical and projected system demand. It is the costs of this real world system that must be allocated, and those costs are heavily driven by demand.

Turning back to the topic of the fixed monthly charge, if the minimum system method is not used for distribution system cost allocation purposes, what, then, is? What, then, are the proper determinants of that component of the customer's bill? I believe we perhaps should answer that question in the same way the majority of other jurisdictions do: the monthly fixed charge should reflect the cost for the service drop, the meter, any other facilities uniquely deployed to connect a customer to the system, to

[77] F. Weston, et al., *Charges for Distribution Service: Issues in Rate Design*, p. 19, Regulatory Assistance Project (2000), available at http://pubs.narus.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

which would be added an allocation of the administrative support costs of meter reading, billing, collections, and customer service.

Given the concerns and issues presented by use of the minimum system methodology, I think that the Company's fixed monthly charges for the several customer rate classes likely already equal or even exceed the level that would be arrived at using the "basic customer method" for cost allocation purposes and the principle of cost causation for purposes of rate design. For example, the current BFC for the residential rate schedule RS is $11.80, whereas the unit cost without minimum system is calculated to be $11.08. See Tr. Vol. 20, p. 77; Pirro Direct Testimony Exhibit 8.

I also note that once the distraction of the minimum system method is removed from consideration, other arguments used to support a higher monthly fixed charge take on a new aspect. As has been stated already, proponents of increasing the fixed charge rely largely on the results of the minimum system method and the principle of cost causation, but they supplement their positions by noting that a fixed monthly charge that is set at a level lower than the fully distributed per customer costs derived from using the minimum system also results in overcompensating for energy efficiency and distributed generation. It does this, they say, by artificially increasing the energy charge component of customer rates. However, once we conclude that the Company's current fixed monthly charge already fully compensates for properly allocated fixed customer costs, using the "basic customer method," then the issue of overcompensation or undercompensation for energy efficiency and distributed generation falls away. This is so because so long as the Company's fixed monthly residential customer charge fully covers the properly allocated customer portion of its costs, the remainder of the established rate will reflect only the demand and energy costs allocable to that customer class.

If, as I believe the evidence clearly shows, the Company's current fixed monthly charge for residential customers already covers its fixed costs were the basic customer method of cost allocation used, then certain other issues that occupy the majority's attention would also disappear. The majority expresses concern about internal subsidization within the residential rate classes when fixed costs are apportioned to the energy rate, thereby penalizing high usage customers and benefitting lower usage customers. But again, if the existing fixed monthly charge is already set at a level that compensates the Company for its fixed per-customer costs, using a method other than the deeply flawed minimum system, no such subsidization is occurring.

The one virtue of a high fixed charge component of bills is that it improves revenue stability for the Company; the higher the fixed component, the more stable revenues will be. While this is not an unimportant consideration, it does not outweigh the conceptual flaws and difficulties in execution involved in the minimum system method. There are other, and in my view better, methods for addressing the utility's need for stable revenues. I am optimistic that the Public Staff and utilities' pending work to further evaluate use of the minimum system method and alternative methods for allocating distribution will "bear fruit" and appropriately inform future decisions. In this regard, I concur with Mr. Weston's admonition in his report, to be practical. He further states that:

> [T]here is the designation of a cost as either customer or demand, which will affect both how costs are divvied up among classes and who within each class will pay them (i.e., both inter- and intra-class allocations). While there is a touch of cynicism in the observation that there is no shortage of academic arguments to justify particular outcomes, it is nevertheless largely true. Always be aware of the revenue effects of a particular rate structure. Who benefits, who loses? Fixed prices, because they recover revenues by customer rather than by usage, invariably shift a larger proportion of the system's costs to the lower-volume consumers (residential and small business). The positions that interested parties take with respect to rate design should, in part, be considered in light of their impacts on class revenue burdens and on the profitability of the utility. Here the admonition to be practical cannot be stressed enough.

F. Weston, et al., Charges for Distribution Service: Issues in Rate Design, p. 19, Regulatory Assistance Project (2000), available at http://pubs.narus.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

Finally, I take note of the fact that the evidence before the Commission in this case concerning the Company's proposed Power Forward initiative and its associated request for a cost recovery rider provides additional grounds that would tend to support rejecting the minimum system method as a means for assigning distribution plant costs to the several customer classes. In response to a question posed at the hearing concerning the impact, if any, of the planned targeted undergrounding investments on the application and output of the Company's minimum system method, the Company offered the following explanation in a post-hearing submission. Currently, underground distribution facilities are not considered by the Company to be part of a "minimum system," since they are considered non-standard installations. As a result of the Company's proposed Targeted Undergrounding Program, this would change, and underground installations will then be considered components of a "minimum system." See DEC Late-Filed Exhibit Regarding Planned Change to Minimum System Methodology (April 6, 2018). Because, subject to variation and exceptions, underground plant is generally more costly than overhead facilities, this would result in a greater total distribution plant cost assigned to each of the customer classes than is presently the case. Further, because the residential rate class has by far the most numerous membership, most of this additional "minimum system" cost would very largely fall on that class. Not surprisingly, this will almost certainly mean that in future rate cases the Company will contend that its per customer cost of service, derived in part from application of the minimum system method, is even higher than it is today, thereby warranting a further increase in the fixed monthly per customer charge. Most likely, this same result will obtain with respect to some other elements of the Power Forward investments, such as the creation of distribution system redundancies that will be necessary to support a self-optimizing and self-correcting distribution system.

The theoretical objections to the minimum system methodology are even more apt in the case of the proposed Power Forward investments. Correlation between the need for underground plant and the number of customers on the system is vanishingly weak; as explained by the Company, the need for underground distribution plant is instead driven by the density, age, and condition of vegetation and by animal and bird populations along distribution lines. The purpose of undergrounding plant is to protect the distribution system from service interruptions, a demand-related concept, and is not dependent on the number of customers whose aggregate demand is at risk of interruption. I find it difficult to consider these investments to be part of a "minimum system." Certainly, they may improve the reliability and resilience of the distribution grid, but these are enhancements to a "minimum system," not elements of it. The point here is that what constitutes a "minimum system" for purpose of cost allocation among customer classes requires the exercise of judgment; it is not something that is self-evident. In my judgment, including the types of distribution plant upgrades that are contemplated by the Power Forward system in the "minimum system" strays too far from the theoretical justification that supports use of the minimum system methodology.

I recognize that the majority is not yet prepared to move to the basic method over the minimum system method in spite of the implications for the fixed monthly charge. Nonetheless, in light of the legitimate issues raised with respect to the minimum system method and the Commission's decision that these issues are sufficient to warrant greater in depth investigation, I believe the counsel of prudence would be to leave the current level of the fixed monthly charges in place pending that consideration, especially in light of the lack of any need for additional revenue. That is an outcome I could have supported; I do not support increasing the residential fixed monthly charge by $2.20 per month.

IV. Cost-Effectiveness and Prudence of Advanced Metering Infrastructure (AMI)

The majority approves DEC's request to recover its costs of replacing Advanced Meter Reading (AMR) meters with AMI, and DEC's recovery of the remaining book value of its AMR meters. The majority reasons that DEC's AMI costs are reasonable, and that DEC's decision to replace its AMR meters with AMI was prudent. I do not question the reasonableness of DEC's AMI costs. However, based on the evidence I conclude that DEC's deployment of AMI is not cost-effective and, largely as a result of that lack of cost-effectiveness, DEC's decision to deploy AMI was not prudent. Therefore, I would deny DEC's request to recover its AMI costs in this proceeding, but allow DEC to defer those costs, with no carrying charge, until a future general rate case in which DEC produces substantial evidence that AMI is cost-effective.

A. DEC's Failure to Comply with Rule R8-60.1

The Majority Order includes the details of the pertinent proceedings under Commission Rule R8-60.1, the rule on smart grid technology plans. In addition, the following segment from the Commission's March 29, 2017 Order Accepting Smart Grid Technology Plans (SGTP Order), in Docket No. E-100, Sub 147, is of note. After citing several requirements of Commission Rule R8-60.1 with respect to the information to be provided by the electric utilities for smart grid technologies currently being deployed or scheduled for implementation within the next five years, the Commission stated:

> [t]he Commission notes that neither DEC, DEP nor DNCP included the above information in their 2016 SGTPs with regard to any future plans for deployment of AMI meters. The Commission interprets this to mean that DEC, DEP and DNCP currently have no plans to replace existing meters with AMI meters, either incrementally or on full scale, during the next five years. As a result, the Commission expects DEC, DEP and DNCP to provide the Commission with the above information, as well as any other required information, in their SGTP filings prior to implementing an incremental or full scale effort to replace existing meters with AMI meters.

SGTP Order, p. 17.

Commission Rule R8-60.1(c)(3) requires the electric utilities to provide the Commission with a cost-benefit analysis and other detailed information about smart grid technologies currently being deployed by the utilities or scheduled for implementation within the next five years. One purpose of the rule is to allow the Commission, Public Staff and other interested parties to review information about proposed smart grid programs, request additional information when needed, and have input regarding the implementation of smart grid programs well in advance of their implementation. Smart grid technologies are relatively new and evolving projects that require substantial capital investments. Therefore, the public interest is best served by the Commission and parties having sufficient time to study and understand the details of a smart grid project before it is launched. DEC appears to support this purpose. In his rebuttal testimony, in response to EDF witness Alvarez's recommendation that the Commission review DEC's AMI project in a separate docket, witness Schneider testified:

> [T]he Commission already has a SGTP rule and dockets to review, allow for intervenor investigation and comment, and ultimately accept, modify or reject the Company's SGTP and those of other utilities.

Tr. Vol. 18, p. 342.

Notwithstanding DEC's understanding of and appreciation for the Commission's SGTP rule, as noted above DEC did not provide a cost-benefit analysis and other required information in its 2016 SGTP to support an AMI deployment. Consequently, the Commission directed DEC "[t]o provide the Commission with the above information, as well as any other required information, in their SGTP filings <u>prior to implementing an incremental or full scale effort</u> to replace existing meters with AMI meters." SGTP Order, at p. 17 [emphasis added] Nevertheless, DEC, as it stated in its May 5, 2017 supplemental filing, began deploying AMI meters "in early 2017." Thus, DEC began its deployment of AMI before complying with the requirement to file the cost-benefit analysis and other information required by Commission Rule R8-60.1, and in contradiction to the Commission's 2016 SGTP Order.

The Commission, by its SGTP Order issued on March 29, 2017, accepted DEC's 2016 SGTP as originally filed. In its May 5, 2017 supplemental filing, DEC stated that in late 2016 it decided to begin a full scale deployment of AMI in North Carolina, even though DEC had stated in its 2016 SGTP, filed on October 3, 2016, that it was studying whether to implement AMI. DEC's decision to begin a full scale AMI deployment "in late 2016" must have been made in November or December of 2016. Further, DEC stated in its supplemental filing that it began deploying AMI meters "in early 2017." Yet DEC waited until May 5, 2017, to inform the Commission of its decision to begin AMI deployment and its implementation of that decision. DEC's May 5, 2017 supplemental filing was a substantial amendment to its 2016 SGTP. DEC did not request that the Commission issue an order accepting its amended 2016 SGTP. More importantly, the Commission did not issue an order accepting DEC's amended 2016 SGTP.

Based on the foregoing, I conclude that DEC failed to comply with the letter and the spirit of Commission Rule R8-60.1. The result was that DEC defeated the ability of the Commission, Public Staff and other interested parties to provide advance input regarding the implementation of AMI. Instead, DEC made the decision to deploy AMI and began implementing that decision without informing the Commission and obtaining the Commission's acceptance of that significant revision to DEC's 2016 SGTP. To be clear, I do not base my denial of DEC's AMI cost recovery on its failure to comply with Rule R8-60.1. However, I do find it important in providing context to my analysis.

B. <u>Cost-Effectiveness of DEC's AMI</u>

In DEC's supplemental information filing on May 5, 2017, in the SGTP Docket, DEC stated that it would be replacing approximately 1.32 million AMR meters from 2017 through 2019. (Supplemental Filing, p. 2) In the AMI cost-benefit analysis filed by DEC as a part of its supplemental filing, DEC concluded that its AMI deployment would result in net benefits having a present value of $117.1 million. (Supplemental Filing, Exhibit No. 2) The largest category of benefits included in the analysis is entitled "Non-technical line loss reduction - power theft, equipment failures and installation errors" (NLLR). It is the last column of benefits shown on Exhibit No. 2, and totals $634.8 million. In comparison, the next largest category of benefits is "Reduced meter operations costs – consumer order workers for meter orders," a total of $175.4 million. According to the cost-benefit analysis, the total of the AMI benefits is $1.007 billion. Thus, the NLLR portion of the benefits is 63% of the total.

In response to question number 2 included in the Commission's SGTP Presentation Order, DEC stated, in pertinent part:

> According to a 2008 EPRI report, industry experts project that a reasonable percentage for non-technical losses is 2% of gross revenue. This assumption was utilized in calculating the DEC AMI benefits.

DEC's First Responses, p. 5.

During DEC's SGTP presentation, DEC witness Schneider was asked whether EPRI or any other entity performed a physical real world study to verify the 2% NLLR figure. Witness Schneider responded:

> Not to my knowledge. I think they went on data. Again, this was a report, not necessarily a study but it was a report, and they were going off of other reports and studies going back years and years that came up with this on average 2 percent of gross revenues so they did not.

SGTP Presentation, Tr., p. 40.

Witness Schneider also stated that DEC has not performed a study that confirms the 2% NLLR factor reported by EPRI. In addition, witness Schneider stated that based on DEC's cost-benefit analysis the costs of the AMI deployment would outweigh the benefits until 2025. SGTP Presentation, Tr. Vol. 18, p. 44.

In the Commission's Additional Information Order, the Commission requested that DEC provide the following information:

> 8. Using the actual historical kilowatt-hour and lost revenue data for energy theft that DEC has experienced and is discovering in North Carolina, including during its AMI deployment, develop an independent estimate of the percent of additional revenues DEC will collect via that deployment that would otherwise be lost due to theft and other non-technical losses.
>
> 9. Provide a revised 20-year AMI cost-benefit analysis that includes: (a) the costs of replacing AMI meters at the end of their 15-year lives, (b) the most recent estimate of the costs of cellular direct connect meters, (c) the cost of replacing other components and software at reasonable intervals, and (d) the non-technical revenue loss estimate (rather than the EPRI 2% estimate) developed pursuant to question 8.

DEC's revised AMI cost-benefit analysis was attached to DEC's Second Responses and filed in the SGTP Docket on December 15, 2017, as Exhibit No. 2. The largest category of benefits included in the analysis continues to be "Non-technical line loss reduction - power theft, equipment failures and installation errors." However, the amount of the NLLR benefit went down from $634.8 million to $448.8 million. In addition, the revised cost-benefit analysis, which includes the cost of replacing AMI meters at the end of their 15-year useful life, shows that AMI deployment would result in net costs having a present value of $49.9 million (DEC's Second Responses, Exhibit No. 2).

DEC witness Schneider takes issue with the Commission's requirement that DEC include in its revised cost-benefit analysis the costs of replacing AMI meters at the end of their 15-year lives. Witness Schneider stated that this adjustment was not a conventional part of DEC's usual business case assessment. He opined that it essentially doubled the cost of the replacement meters over a 30-year period, but only accounted for the benefits of the meters for 15 years, the life of the current AMI meters being deployed by DEC. Tr. Vol. 18, pp. 408-14.

I am not persuaded by witness Schneider that the cost of replacing AMI meters at the end of their 15-year useful life should not be included in the AMI cost-benefit analysis. Public Staff witness Maness testified that DEC's existing AMR meters have an average remaining useful life of 15.4 years, and that this is the period of time that should be used to calculate DEC's annual AMR depreciation expense. Tr. Vol. 22, pp. 103-04. Further, there is no contention or evidence that DEC's AMR meters are not functioning properly or are not serving their intended purpose. Nevertheless, DEC is requesting that ratepayers pay for discarding the AMR meters and replacing them with AMI. In addition, the AMI meters being deployed by DEC were manufactured in 2009. Tr. Vol. 18, pp. 374-75. Based on these facts, it is reasonably likely that in 15 years, or perhaps sooner depending on further developments in AMI technology, DEC could be before the Commission requesting to scrap its 2009 AMI meters and to replace them with the latest metering technology. As a result, it is appropriate to include in DEC's cost-benefit analysis the cost of replacing in 15 years the AMI meters presently being deployed by DEC.

I conclude that the first cost-benefit analysis produced by DEC was not properly structured, and, therefore, it was not reasonable for DEC to rely on that analysis in deciding to fully deploy AMI. The first analysis was not properly structured because, as noted above, it did not include the cost of replacing the AMI meters after 15 years. In addition, DEC's first cost-benefit analysis was not properly structured because DEC used the EPRI 2% NLLR factor.

In the December 2008 EPRI Report, EPRI noted the following reasons for non-technical losses:

- Non-performing and under-performing meters.
- Incorrect application of multiplying factors.
- Defects in current transformer and potential transformer circuitry.
- Non-reading of meters.
- Pilferage by manipulating or bypassing meters.
- Theft by direct tapping and so on.

2008 EPRI Report, pp. 1-3.

With regard to the measurement of non-technical losses, the EPRI Report stated:

> Non-technical losses, by definition, are losses that are not accounted for and are, therefore, not subject to analytical measurement. Non-technical losses are simply the difference between the energy delivered to the

> distribution system and billed to end-users, less technical losses. Although there is agreement on the importance of non-technical losses, there is no firm data to define the level of losses on an industrywide basis. However, the importance of non-technical losses, especially in terms of their impact on revenue, is such that distribution utilities try to quantify them.
>
> Such quantification is very difficult. Quantifying what statisticians call "unaccountable for" attempts the impossible. There is an inherent difficulty in obtaining data on unmetered supplies and theft. Estimating the revenue impact of non-technical losses presents yet further difficulties. This is brought into relief when trying to measure the benefits of AMI in reducing non-technical losses. Although there are expectations that AMI will help to reduce non-technical losses, the measurement of benefits (or costs) from AMI deployment are considered non-quantifiable.

2008 EPRI Report, p. 1-7 (emphasis added).

The above discussion about the difficulty of quantifying NLLR is not convincing, particularly with regard to DEC. I accept the statement in the EPRI Report that "there is no firm data to define the level of losses on an industrywide basis." However, DEC had no reason to measure NLLR on an industrywide basis. DEC has been providing electric service in North Carolina for over 100 years. Consequently, DEC has a wealth of experience and knowledge about the components that make up NLLR, such as non-performing and under-performing meters, and theft losses. Therefore, it was unnecessary and unreasonable for DEC to use EPRI's 2% NLLR factor rather than DEC's actual NLLR amount. As a result, with respect to determining the cost-effectiveness of DEC's AMI deployment, I give no weight to DEC's first cost-benefit analysis.

Instead, I give substantial weight to the revised cost-benefit analysis provided by DEC on December 15, 2017. The revised cost-benefit analysis, using DEC's actual NLLR numbers, is a reasonable and accurate methodology for projecting the costs and benefits of AMI, and, therefore, is probative evidence of such costs and benefits.

The majority gives substantial weight to DEC's evidence of future energy saving and peak shaving rate designs that can be supported by AMI. In DEC's Supplemental Filing, DEC discussed the possibility of additional customer services to be provided by AMI.

> [A]MI is the foundational investment that will enable enhanced customer solutions – giving customers greater control, convenience and choice over their energy usage, while also giving customers the opportunity to budget, save time and money. AMI technology allows a utility to gather more granular usage data and utilize new capabilities to offer new programs and services to customers that are not achievable through existing meters. The AMI technology will pave the way for programs that will allow customers to stay better informed during outages, control their due dates, avoid deposits, to be reconnected faster, and to better understand and take control of their energy

> usage, and ultimately, their bills. Over time, the Company also expects AMI meters to contribute to cost reductions from reduced truck rolls in the years after deployments.

Supplemental Filing, p. 1.

In the Commission's SGTP Presentation Order, with regard to the above statement, question number 7 asked DEC to "Explain fully whether and how all of the costs for developing and deploying those services are included in the cost-benefit analysis." In response, DEC stated:

> No costs or benefits for developing and deploying additional customer programs/services were included in the AMI cost –benefit analysis.

DEC's First Responses, p. 8.

Nevertheless, during cross-examination by DEC's counsel witness Schneider stated:

> [t]here is a lot of additional customer programs and benefits that the AMI, as a foundation, enables that, again, we didn't have those costs and benefits in our cost-benefit model because they just weren't designed yet. We didn't know what the costs were in each of those cases, you know, will be on their own. So in general, with a positive business case, and plus the fact that we know there is additional customer products and services that this solution can enable, the Company has made a decision that this is a viable project that we want to move forward with.

Tr. Vol. 18, pp. 413-14.

I give no weight to witness Schneider's testimony regarding possible new rate designs, additional customer programs and additional customer benefits not identified and not included in the cost-benefit analysis. DEC has the proverbial cart before the horse. Future possible rate designs and other measures that may be developed and that may provide customer benefits are much too speculative for the Commission to accept as probative evidence.

Public utilities are required to provide cost effective services. G.S. 62-2. DEC's revised AMI cost-benefit analysis shows that on a present value basis the cost of DEC's AMI deployment is $49.9 million more than the benefits. In addition, another major cost of DEC's AMI deployment is the lost value of DEC's AMR meters, which will be approximately $85 million.[78] The AMR meters still have 15 years of useful life and are serving their

[78] DEC's 2017 SGTP Update stated that the remaining net book value of its AMR meters was an estimated $127.66 million as of March 31, 2017. However, in the SGTP presentation witness Schneider

intended purpose. Nevertheless, DEC would discard the AMR meters and recover the loss of the approximately $85 million book value from DEC's ratepayers.

Moreover, DEC proposes to include in its new rates the recovery of AMI costs and the recovery of AMR stranded costs. The result would be that DEC's customers would be paying for AMI and AMR meters for the next 15 years. Yet, even under DEC's initial cost-benefit analysis, ratepayers would not see the net benefits of AMI until 2025. Thus, there would be a period of seven years in which DEC's ratepayers would be paying for AMI meters without receiving net benefits from those meters, and paying for AMR meters that have been scrapped by DEC. Based on the present value of the cost of DEC's AMI deployment being $49.9 million more than the benefits, the loss of 15 years of useful life of DEC's existing AMR meters, and the double meter costs that ratepayers would be required to pay for several years, I conclude that a preponderance of the evidence shows that DEC's AMI deployment is not a cost-effective method of providing service.

C. <u>Prudence of DEC's AMI Implementation</u>

In Docket No. E-2, Sub 537, the Commission addressed alleged imprudence by Carolina Power & Light (CP&L), DEP's predecessor, in the construction of the Shearon Harris Nuclear Plant. The Commission disallowed certain costs of construction based on its findings of imprudence by CP&L that resulted in unreasonable delays and avoidable errors in the construction of CP&L's Harris plant. 78 North Carolina Utilities Commission Orders and Decisions 238 (August 5, 1988) (<u>Harris Order</u>); <u>reversed in part, and remanded</u> (on other grounds), <u>State ex rel. Utilities Comm'n v. Thornburg</u>, 325 N.C. 484, 385 S.E.2d 463 (1989). The Commission stated the general standard of prudence as

> [w]hether management decisions were made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or reasonably should have been known at that time (citation omitted)…The Commission notes that this standard is one of reasonableness that must be based on a contemporaneous view of the action or decision under question. Perfection is not required. Hindsight analysis – the judging of events based on subsequent developments – is not permitted.

<u>Harris Order</u>, at 251-252.

As previously discussed, DEC's first cost-benefit analysis was not properly structured because it included DEC's use of the EPRI 2% NLLR factor. It was unnecessary and unreasonable for DEC to use EPRI's 2% NLLR factor rather than DEC's actual NLLR experience. With respect to determining the prudence of DEC's AMI deployment, I give substantial weight to DEC's use of its first cost-benefit analysis in

testified that DEC would receive tax benefits that would reduce the lost book value to approximately $85 million. (SGTP Presentation, Tr., pp. 42-43.)

making the decision to deploy AMI. It was not reasonable for DEC to rely upon that analysis in deciding to fully deploy AMI and, therefore, DEC's decision to deploy AMI was not a prudent decision.

In addition, I give substantial weight to the testimony of Public Staff witness Maness that DEC's existing AMR meters have an average remaining useful life of 15.4 years, and that 15 years should be the length of time for recovering the AMR depreciation expense. The evidence in the present case does not support DEC's decision to discard AMR meters that are properly functioning and have 15 years of useful life, particularly when it leads to the unjust result that DEC's ratepayers pay the remaining $85 million book value of the AMR meters. DEC had all of this information in late 2016 when it made its decision to fully deploy AMI. In fact, DEC's 2017 SGTP Update stated that the remaining net book value of its AMR meters was an estimated $127.66 million as of March 31, 2017. Thus, when DEC began deploying AMI meters in early 2017 DEC knew that its decision meant that ratepayers would be required to pay somewhere between $127 million and $85 million for discarded AMR meters. Based on these facts, it was not reasonable for DEC to decide in early 2017 to fully deploy AMI meters and to discard its AMR meters. Therefore, DEC's decision to deploy AMI was not a prudent decision.

Finally, as previously discussed, DEC proposes to include in its new rates the recovery of AMI costs and the recovery of AMR stranded costs, which would result in DEC's customers paying for AMI and AMR meters for the next 15 years, even though under DEC's initial cost-benefit analysis ratepayers would not see the net benefits of AMI until 2025. Thus, there would be a period of seven years in which DEC's ratepayers would be paying for AMI meters without receiving net benefits from those meters, and paying for AMR meters that have been discarded by DEC. DEC had these facts when it decided to begin deploying AMI meters in early 2017. Based on these facts, at the time of the Company's decision in early 2017, it was not reasonable nor prudent for to deploy AMI meters and to discard its AMR meters.

Applying the Harris Order standard of prudence to the above facts, I conclude that a preponderance of the evidence shows that DEC's AMI deployment was not a prudent action when DEC began deploying AMI meters in early 2017. Therefore, I would deny DEC's request to recover its AMI costs, but authorize DEC to place its present AMI costs of $90.9 million and its future AMI costs in a deferred account, with no carrying charge, and to seek recovery of those costs in a future general rate case. In addition, I would require that DEC continue depreciating its AMR meters as presently scheduled, and remove AMR meters from rate base as they are replaced.

V. CONCLUSION

My conclusions in summary are these:

(a) that the Majority Order imposes on ratepayers a substantial amount of costs directly attributable to the Company's imprudent management of its waste coal ash impoundments at the Dan River plant, imprudence that produced the release of waste ash into the Dan River in February, 2014;

(b) that the Majority Order improperly shifts to present and future customers a substantial amount of costs for closure of the Company's waste coal ash impoundments that should have been charged and collected from prior customers for electricity service provided in the past;

(c) that the Majority Order, without proper analysis or foundation in law or in record evidence, impermissibly authorizes the Company to earn a return, or profit, from the deferred amounts expended by the Company in the period 2015 through 2017 for costs related to the closure of its waste coal ash impoundments;

(d) that the Majority Order, again without basis in the record and in a manner that unfairly discriminates among different classes of customers, permits the Company to increase the fixed monthly charge to its residential customers, even though the majority decision finds that the Company does not require any increase in revenue from residential customers or from any other class of customers; and

(e) that the Majority Order improperly permits the Company to include in its rates the costs of replacing existing customer meters with new advanced technology meters, even though the existing meters have not reached the end of their useful lives and the Company is not presently able to offer to customers any material benefits from the new advanced technology meters.

For these reasons, I cannot conclude that the rates that will follow from the Majority Order are just and reasonable as required by law. I therefore dissent. In addition, I join in the dissenting opinion filed in this matter by Commissioner ToNola D. Brown-Bland.

_____/s/ Daniel G. Clodfelter______
Commissioner Daniel G. Clodfelter

DOCKET NO. E-7, SUB 1146
DOCKET NO. E-7, SUB 819
DOCKET NO. E-7, SUB 1152
DOCKET NO. E-7, SUB 1110

Commissioner ToNola D. Brown-Bland, concurring in part and dissenting in part:

I respectfully dissent in part from the majority opinion and join in the dissenting opinion of Commissioner Clodfelter with respect to the decision to allow an increase in the fixed monthly residential charge; the approval of cost recovery in this general rate case for both the deployment of Advanced Metering Infrastructure (AMI) meters and the depreciation of Advanced Meter Reading (AMR) meters being replaced by AMI deployment 15 years before the end of their useful life; and the approval of waste coal ash cost recovery such that the Company ultimately will be permitted the opportunity to recover over 97% of its total projected waste coal ash removal costs of $2.6 billion from the ratepayers of North Carolina, despite substantial evidence of the Company's imprudent choices and actions leading to the incurrence of certain specific and identifiable costs. It is my opinion that each of these decisions is contrary to the Commission's charge to make rates that are just and reasonable. See G.S. 62-2 and 62-130.

A. Fixed Monthly Residential Charge

I join in Commissioner Clodfelter's dissenting opinion to the extent he finds that the majority decision to increase the residential fixed charge from $11.80 to $14 is not supported by any evidence of record, let alone substantial evidence as is required for all Commission decisions pursuant to G.S. 62-65, and to the extent of the shortcomings and criticisms he finds regarding the majority's "subsidization" and "cost causation" rationales for increasing the fixed residential charge by $2.20 per month. I further point out that while the increase to $14.00 appears to be arbitrary, it just happens to be the same as the fixed residential customer charge adopted in the Commission's Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, Docket No. E-2, Sub 1142, on February 23, 2018. (DEP Order).[79] In the DEP Order, $14.00 was the agreed upon amount accepted and settled upon in the Stipulation between the Public Staff and DEP. Given the cost evidence of record in the DEP case and the give-and-take of settlement negotiations leading to the Stipulation between the Public Staff and DEP, combined with the continued use and acceptance of the minimum system cost allocation method at the time of the Commission's decision, I found the

[79]Choosing the monthly fixed cost charge for DEC based on the charge the parties stipulated to in DEP would not be in keeping with the requirement to set just and reasonable rates based on substantial evidence. As DEC witness Pirro testified, "Other utilities'' cost and rates are not relevant to a determination of DEC's rates." He explained that rates should be set based on examining a utility's own cost of service. Tr. Vol.19, p. 84.

Commission's acceptance of the stipulated $14.00 charge for the fixed cost portion of the residential rates reasonable for DEP and its customers.

In contrast, in the present DEC rate case, there is no settlement or stipulation of the Company's request to increase the monthly fixed charge, there is no substantial support in the record suggesting that the fixed cost attributable to the residential class has increased over what was supported and found reasonable when the Commission set the Company's current rates, and thus no substantial evidence that an increase in the fixed cost portion of the residential rate is appropriate at this time. Moreover, the Company's overall revenue requirement is being decreased in the present general rate case, suggesting that any alleged subsidy effect cited by the majority is already minimized to a degree by the lesser revenue requirement, alleviating the perceived need to increase the residential fixed charge in haste.

Additionally, while the majority states a concern about minimizing subsidization, its focus is unfairly and discriminatorily upon only the residential class of customers. The Company requested that the Commission increase the monthly fixed charge for all classes of customers including the non-residential classes. That the Company sought to increase non-residential fixed charges based on DEC's cost of service indicates the Company's position and belief that its current non-residential rates are not properly balanced between fixed charges and demand charges, and that it believes that interclass subsidization exists within the non-residential classes similarly to the subsidization it believes is present in the current rates for the residential class. The majority opinion brushes off this concern even though the Company was obviously aware that its subsidization and cost causation concerns should not apply to one class to the exclusion of others. Finally, while the majority has set the residential fixed charge at the same mark as it did in the DEP Order, DEC and DEP sought different levels of fixed cost charges for each of the two companies, recognizing them to have different cost structures. It is inexplicable that the majority would cause DEC ratepayers to pay the same fixed cost charge as DEP, when the evidence produced by the utilities in their respective cases tends to show that DEP's cost of service is higher than DEC's—an indication that the majority's decision is not based on actual costs.

With respect to the $14.00 fixed monthly residential charge sanctioned for DEC and its ratepayers, the majority opinion relies heavily on the concept that this charge strikes a proper balance and better reflects actual cost causation. However, no party presented evidence supporting $14.00 as the actual fixed residential cost of service. The majority claims to have chosen a cost number from within a range suggested by two different models for determining cost causation, but the evidence shows that the cost is either at the higher minimum system cost of $23.78 or at the lower basic customer cost method of $11.08. Choosing a random number between the two ends offered as evidence without a rational basis does not meet the Commission's obligation to set just and reasonable rates based on substantial evidence. See G.S. 62-65 and 62-131.

In addition, due to the flaws with and the need to review the use of the minimum system methodology which impacts the Company's rate design with respect to customer fixed cost charges (particularly in light of the likelihood that costly additions the Company plans to make to move its power system forward could have the effect of further increasing the fixed cost portion of the rates), I join in Commissioner Clodfelter's call first to have the benefit of access to the Commission-ordered evaluation of options for distribution system cost allocation and a study of consistent application of methodology prior to making any increase in the fixed monthly charge to residential ratepayers. As long as there is the reasonable possibility that after the Commission-ordered evaluation, the fixed distribution costs attributable to residential customer will be less than $14.00, it is unfair and unnecessary to increase this charge at this time given that in this general rate case the Commission has determined that the Company has no need for any additional revenue requirement. At this point in time, the increase in the fixed residential charge would appear to have more to do with stabilizing company revenues than with following cost causation principles or easing the burden of within-class subsidization through demand charges.

Accordingly, I find that the majority's increase of the monthly fixed residential charge is unjust and not reasonable based on the record before the Commission.

B. Recovery of Meter Costs

I join in Commissioner Clodfelter's dissent agreeing with him that DEC should not be allowed to recover AMI costs in this rate case but should instead be allowed to defer such costs until its next general case in which it could recover the deferred costs on producing substantial evidence that the Company's deployment of AMI meters is cost effective. I write to add that with the provisions that require the Company to move promptly to bring customers benefits from placing AMI meters in service such that ratepayers' likelihood of receiving value from paying for this new technology well before 2025, and before possible obsolescence of the new meters, is greatly increased, I would approve the Company's request to recover its AMI costs in this rate case, but for the majority's decision requiring ratepayers to continue paying for "new" and currently used and useful AMR meters at the same time they are to pay for new AMI meters. If the ratepayers were not required to pay for the AMR meters which still have a useful life of 15 years, I would find the decision to deploy AMI meters at this time prudent and cost effective.

It is patently unfair, unjust and unreasonable that the Company be allowed to make a unilateral decision stranding its own assets and then have the ratepayers pay for a decision within DEC's own control not only to strand its assets but also to strand them at a time when nearly $128 million in undepreciated value (reduced to $85 million by tax benefits) remained on the books. The majority's decision in essence means that ratepayers will be paying for two "shiny objects" at one time while they are able to use only one. There are certainly instances where allowing for recovery of stranded assets which represented a reasonable and prudent spend at the time of construction or deployment is the right decision, but when the utility's assets are stranded by its decision, made unilaterally on its own, and the assets are stranded with substantial useful life and functionality remaining, this is not one of those instances. I would protect the ratepayers from this situation and impose at least some of the cost for this decision to strand assets on the Company. There is no compelling evidence in the record that suggests that deploying AMI now and creating a stranded asset with many years of remaining useful life is necessary to the continued provision of safe, reliable, affordable and good quality service. It is unfair that ratepayers must continue paying for AMR for the next 15 years and not receiving benefit from those meters during a significant portion of that time period and also not receiving much additional benefit from the new replacement meters until some indefinite time in the future.

C. Recovery of coal ash basin closure costs

I join in the dissenting opinion of Commissioner Clodfelter and would allow recovery of some coal ash basin closure costs and deny others as he has well-detailed. I write to add that it is an unfair result that the majority's decision paves the way toward the ratepayers being responsible to pay over 97% of the Company's projected total waste coal ash removal costs of $2.6 billion in light of imprudent choices and actions by the Company that resulted in the incurrence of a significant portion of the costs now sought from the ratepayers.

Being imprudent or taking an action that is imprudent is not unlawful. On the other hand, committing an act that is unlawful, whether in violation of a criminal law, a regulation or a civil duty, is imprudent. Being imprudent with respect to an action or choice means being practically unwise, not careful, not cautious, or not circumspect. See Black's Law Dictionary, "Prudent," p. 1226 (West Publishing Co., 1990) (definition in pertinent part). The concept of imprudence is so basic and well-understood that we "know it when we see it" and analytic gymnastics is not required in order to recognize it. The same is true of imprudently incurred costs—these are costs that could have been avoided if the actor (in this case a utility), had made more cautious, wiser, or more careful decisions. A choice made could be a viable option, but still not have been a wise, prudent choice among viable approaches.[80]

Based on the entire record before the Commission, the record is replete with evidence of the Company's imprudent choices and acts of both commission and omission. Just a few examples in addition to those discussed in detail in Commissioner Clodfelter's dissenting opinion are the failure to take action to

[80] Under the North Carolina Public Utilities Act, imprudence on the part of a utility can be found without a showing or establishing of legal violation or breach of civil duty, but if either of those is established, such as by an admission of criminal negligence or by evidence in the record sufficient for a prima facie showing of civil negligence or of negligence *per se,* as I discussed in my dissent in Docket No. E-2, Sub 1142, Commission Order dated February 23, 2018, then a finding and conclusion of imprudence is proper and arguably required.

mitigate or eliminate groundwater contamination at Dan River at least as early as 2007, when based on its own knowledge as expressed in its own document entitled Environmental Management Program for Coal Combustion (Kerin AGO Cross Ex. 3), it should have realized the imprudence of a “minimum compliance with law” stance as opposed to taking actions it knew would have better protected surface and groundwater from contamination; the failure to heed the advice of its program engineers to provide a budget for camera inspection of stormwater pipes running under or through ash basins at the Dan River plant (Kerin AGO Cross Ex. 6); and the failure to follow its own closure plans to promptly begin dewatering the impoundments at Dan River following retirement of the coal units in 2012. Each of these actions or non-actions involved imprudent unwise decisions or choices and each led to specific identifiable costs that are included among the costs the Company and the majority would have the ratepayers pay nearly in their entirety.

Despite a record full of such examples of imprudence, the majority finds no imprudence and, therefore, fails to engage in the exercise of determining waste coal ash removal costs directly (much less indirectly) attributable to instances of imprudence on the Company’s part. Not only does the record reveal imprudence in handling, storing, maintaining and monitoring waste coal ash just as it did in the DEP Rate Case, but as Commissioner Clodfelter explains, imprudent administrative and management decisions, such as not seeking recovery for basin closure costs in earlier rate cases, are also established by the evidence of record. Such decisions have led to some of the increased coal ash related costs being sought in this case from ratepayers far removed from the generation of ratepayers who received the benefit of electric service leading to the ash residue which is the subject of the costs sought by the Company today.

While, for many reasons, it is difficult and in some cases impossible to determine from the record all the costs attributable to the Company’s imprudence, chasing perfection should not be allowed to become the enemy of the good. There is evidence in the record that permits identification and disallowance of specific discrete costs and/or cost increases caused by identifiable and known acts of imprudence. It is the better course of action, through disallowance of these costs, to have the ratepayers, who benefitted from affordable electricity service fueled by coal, and the Company and its shareholders reasonably share in the costs of waste coal ash removal and basin closure than to avoid the exercise of parsing through costs to distinguish between those that were prudently incurred and those that were not. An arbitrary monetary amount without rational basis chosen as a one-time management penalty cannot substitute for the Commission’s duty to make rates that are fair to both the Company and its ratepayers on a case by case (incurrence by incurrence) basis considering all evidence of record in each individual case.

/s/ ToNola D. Brown-Bland
Commissioner ToNola D. Brown-Bland