STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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-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 DOCKET NO. E-7, 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 1146 In the Matter of Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	PROPOSED ORDER OF THE PUBLIC STAFF

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

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

Tuesday, January 30, 2018, at 6:30 p.m., 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

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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, Request for an Accounting Order and to Consolidate Dockets (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[1]; Scott L. Batson, Senior Vice President of Nuclear Operations, Duke Energy Corporation (Duke Energy); James H. Cowling, Director of Outdoor Lighting, DEC and its affiliated utility operating companies; Stephen G. De May, Senior Vice President of Tax and Treasurer,

[1] DEC is a wholly owned subsidiary of Duke Energy Corporation. (T 6 p 155)

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

Also on August 25, 2017, DEC filed its Request for Approval to Cancel the Lee Nuclear Project and to Consolidate Dockets in Docket No. E-7, Sub 819.

Petitions to intervene were filed by NCSEA on July 26, 2017; CIGFUR on August 8, 2017; CUCA on August 9, 2017; Rate Paying Neighbors on August

[2] DEBS provides various administrative and other services to DEC and other affiliated companies of Duke Energy. (T 4 p 33)

23, 2017; EDF on August 25, 2017; the North Carolina Farm Bureau (NCFB) on September 6, 2017; NC WARN on September 7, 2017; Sierra Club on September 18, 2017; Kroger on September 19, 2017; Appalachian State University (ASU) on September 29, 2017; NCLM on October 3, 2017; EMCs on October 16, 2017; Commercial Group on October 31, 2017; Tech Customers on November 2, 2017; Cities of Concord and Kings Mountain on November 17, 2017; NC Justice Center on December 19, 2017; and City of Durham on January 3, 2018. Notice of Intervention was filed by the Attorney General on August 31, 2017.

The Commission entered orders granting the petitions to intervene of NCSEA on August 7, 2017; EDF on September 5, 2017; NC WARN on September 15, 2017; CUCA on September 18, 2017; CIGFUR, NCFB, and Rate Paying Neighbors on September 19, 2017; Sierra Club on September 27, 2017[3]; Kroger on September 28, 2017; NCLM on October 4, 2017; ASU on October 19, 2017; EMCs on October 20, 2017; Commercial Group and Tech Customers on November 8, 2017; Cities of Concord and Kings Mountain on December 14, 2017; and NC Justice Center and City of Durham on January 11, 2018.

The Public Staff's intervention is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19. The intervention of the Attorney General's Office (AGO) is recognized pursuant to G.S. 62-20.

[3] The Commission filed an Amended Order Granting Petition to Intervene and Motion for Limited Appearance regarding Sierra Club on September 29, 2017.

On July 10, 2017, the Commission issued an Order consolidating DEP's and DEC's requests in Docket Nos. E-2, Sub 1103 and E-7, Sub 1110 to defer coal ash costs with DEP's general rate case application in Docket No. E-2, Sub 1142 (DEP Rate Case) and DEC's next general rate case. In addition, on October 18, 2017, the Commission issued an Order consolidating Docket No. E-7, Sub 1146 with Docket Nos. E-7, Sub 1152 (DEC's request to implement a job retention rider) and E-7, Sub 819 (DEC's request to cancel the Lee Nuclear Project), and allowing those persons who had been granted intervention in those dockets to fully participate in this proceeding.

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. On October 20, 2017, the Commission issued an Amended Order Scheduling Investigation and Hearings, Establishing Intervention and Testimony Due Dates and Discovery Guidelines, and Requiring Public Notice, revising the dates for the filing of Public Staff and intervenor direct testimony and exhibits and Company rebuttal testimony and exhibits.

On November 3, 2017, Sierra Club filed a Motion to Schedule Additional Public Hearing. On December 22, 2017, the Commission issued an Order denying Sierra Club's motion.

On December 15, 2017, DEC filed the supplemental direct testimony and exhibits of its witness McManeus. DEC filed the revised supplemental direct testimony of witness McManeus on December 18, 2017.

On December 19, 2017, DEC filed a revised Exhibit B to its application, a revised Form E1 Item 39b, and a revised Exhibit 1 to the direct testimony of Company witness Pirro.

On January 16, 2018, DEC filed the second supplemental testimony and exhibit of its witness McManeus.

On January 18, 2018, EDF filed the direct testimony of Paul J. Alvarez, President, Wired Group. On January 23, 2018, CUCA filed the direct testimony and exhibits of Kevin W. O'Donnell, President, Nova Energy Consultants, Inc.; Tech Customers filed the direct testimony and exhibits of Edward D. Kee, Affiliated Expert, NERA Economic Consulting, and Kurt G. Strunk, Director, National Economic Research Associates; Kroger filed the direct testimony of Kevin C. Higgins, Principal, Energy Strategies, LLC; NC Justice Center filed the direct testimony and exhibits of Jonathan F. Wallach, Vice President, Resource Insight, Inc., John Howat, Senior Policy Analyst, National Consumer Law Center, and Satana Deberry, Executive Director, North Carolina Housing Coalition; Sierra Club filed the direct testimony and exhibits of Ezra D. Hausman, Consultant, Ezra Hausman Consulting, and Mark Quarles, Principle Scientist and owner, Global Environmental, LLC; NCLM filed the direct testimony of F. Hardin Watkins, Jr., City Manager, Burlington, North Carolina, Brian W. Coughlan, President and owner, Utility Management Services, Inc., Maria S. Hunnicutt, General Manager, Broad River Water Authority, and Adam Fischer, Transportation Director, City of Greensboro, North Carolina; CIGFUR filed the direct testimony and exhibit of Nicholas Phillips, Jr., Managing Principal, Brubaker & Associates, Inc.; 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.; NCSEA filed the direct testimony and exhibits of Caroline Golin, Southeast Regulatory Director, Vote Solar, Justin R. Barnes, Director of Research, EQ Research, LLC, and Michael E. Murray, President, Mission:data Coalition; the Public Staff filed the direct testimony and exhibits of Michelle M. Boswell, Staff Accountant, Public Staff Accounting Division; Jack L. Floyd, Utilities Engineer, Public Staff Electric Division, John R. Hinton, Director, Public Staff Economic Research Division, Jay B. Lucas, Utilities Engineer, Public Staff Electric Division, Michael C. Maness, Director, Public Staff Accounting Division, James S. McLawhorn, Director, Public Staff Electric Division, Dustin R. Metz, Utilities Engineer, Public Staff Electric Division, Scott J. Saillor, Utilities Engineer, Public Staff Electric Division, Tommy C. Williamson, Jr., Utilities Engineer, Public Staff Electric Division, Charles S. Junis, Utility Engineer, Public Staff Water, Sewer and Communications Division, Roxie McCullar, Consultant, William Dunkel and Associates, David C. Parcell, Principal and Senior Economist, Technical Associates, Inc., Vance F. Moore, President, Garrett and Moore, Inc., and L. Bernard Garrett, Secretary/Treasurer, Garrett and Moore, Inc. On January 24, 2018, the Commercial Group filed the direct testimony and exhibits of Steve

W. Chriss, Director of Energy and Strategy Analysis, Wal-Mart Stores, Inc., and Wayne Rosa, Director of Maintenance, Food Lion, LLC; and the Public Staff filed the appendix and exhibits to the direct testimony of witness McCullar.

On January 25, 2018, DEC filed a Motion to Strike portions of the direct testimony of NCSEA witness Murray. On January 26, 2018, DEC filed Motions to Strike portions of the direct testimony of EDF witness Paul J. Alvarez and NC Justice Center witness Howat. On January 30, 2018, EDF filed a response in opposition to DEC's Motion to Strike the testimony of witness Alvarez. On February 1, 2018, NCSEA filed a response in opposition to DEC's Motion to Strike the testimony of witness Murray. On February 2, 2018, NC Justice Center filed a response in opposition to DEC's Motion to Strike the testimony of witness Howat. On February 6, 2018, the Commission issued an Order granting DEC's Motion to Strike portions of the testimony of witness Howat, as well as Orders denying DEC's Motions to Strike portions of the testimony of witnesses Alvarez and Murray.

On January 30, 2018, the Commission issued an Order granting the motion of the Public Staff to postpone the expert witness hearing scheduled to begin Monday, February 19, 2018, to Tuesday, February 27, 2018, at 9:00 a.m.

On January 31, 2018, the AGO filed Exhibit 4.6 to the direct testimony of its witness Wittliff. Also on January 31, 2018, NCSEA filed the corrected direct testimony and exhibits of its witness Golin.

On February 2, 2018, the Commission issued an Order requesting that the Public Staff provide the Commission with the exhibits to the direct testimony of

Public Staff Boswell, as well as any forthcoming revisions to the exhibits and settlement exhibits, in Excel format with all supporting tabs and formulas. On February 5, 2018, the Public Staff filed the exhibits to the testimony of witness Boswell in the format requested by the Commission.

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

On February 7, 2018, DEC filed pages to replace pages 329-335 of Exhibit R12 to the rebuttal testimony of Company witness Hevert.

On February 9, 2018, DEC filed its Objections to the Public Staff's 150th Set of Data Requests. On February 13, 2018, the Public Staff filed a letter with the Commission in which it agreed to withdraw its Data Request 150.

On February 16, 2018, the Commission issued its Order on Hearing Procedure and Availability of Witnesses.

On February 20, 2018, the Public Staff filed the supplemental testimony and exhibits of witnesses Boswell, Hinton, Junis, Maness, Moore, and Saillor. On February 22, 2018, the Public Staff filed the corrected supplemental testimony and exhibits of witness Boswell.

Also on February 22, 2018, DEC filed a motion requesting that Company witness Batson, Public Staff witness Saillor, CIGFUR witness Phillips, Commercial Group witnesses Chriss and Rosa, EDF witness Alvarez, Kroger witness Higgins, and Sierra Club witness Hausman be excused from attending the expert witness hearing, and that their pre-filed testimony and exhibits be accepted into evidence. The Commission issued an Order granting DEC's motion on February 27, 2018.

On February 23, 2018, the Commission issued an Order granting the motion of DEC to postpone the expert witness hearing scheduled to begin Tuesday, February 27, 2018, to Monday, March 5, 2018 at 1:30 p.m.

On February 26, 2018, DEC and the AGO filed a Stipulation as to Admission of Evidence, stipulating that the testimony and associated exhibits of Company witness Fountain regarding insurance coverage given in the DEP Rate Case is appropriate to be admitted into evidence in this docket.

On February 28, 2018, DEC, NCLM, and the Cities of Concord and Kings Mountain filed a Partial Settlement Agreement.

Also on February 28, 2018, DEC and the Public Staff filed an Agreement and Stipulation of Partial Settlement (Stipulation) that resolved all issues between

DEC and Public Staff with the exception of: (1) cost recovery of DEC's coal combustion residuals (CCR) costs, recovery amortization period and return during the amortization period, allocation issues associated with CCR costs, and ongoing costs to be included in rates; (2) regarding the Lee Nuclear Station, whether it is appropriate to allow a return on the unamortized balance of abandonment losses during the amortization period; (3) with respect to DEC's proposed Job Retention Rider (JRR), whether companies involved in the transportation or preservation of raw material or a finished product should qualify, and how, or if, the JRR should be funded after the expiration of the initial year's $4.5 million shareholder contribution; (4) the status of DEC's Nuclear Decommissioning Trust Fund (NDTF) and the Public Staff's proposal to adjust nuclear decommissioning expense; (5) the final update month to be used for ratemaking in this case and what should be included in the update; (6) the methodology for calculating customer usage through December 2017; (7) the manner in which the Federal Tax Cuts and Jobs Act (the Tax Act) should be addressed in this case; (8) the amount of annual depreciation expense and associated accumulated depreciation to be used for ratemaking in this case; (9) whether a Grid Reliability and Resiliency Rider (Grid Rider) should be adopted in this proceeding and, if so, which costs would be included in a Grid Rider, and the structure of a Grid Rider; (10) the amount of the Basic Facilities Charge (BFC); and (11) any other revenue requirement or non-revenue requirement issue not agreed upon by the stipulating parties.

In support of the Stipulation, on March 1, 2018, the Public Staff filed the settlement testimony and exhibits of its witnesses Boswell, Maness, and Parcell, and DEC filed the settlement testimony and exhibits of its witnesses Fountain, De May, Hevert, McManeus, and Pirro.

Also on March 1, 2018, DEC requested that Company witness McGee, NCSEA witness Murray, NCLM witnesses Watkins, Hunnicutt, and Fischer, and Tech Customers witness Strunk be excused from attending the expert witness hearing, and that their pre-filed testimony and exhibits be accepted into evidence. The Commission issued an Order granting DEC's request on March 5, 2018.

On March 2, 2018, DEC filed Revised Exhibit 1 to the settlement testimony of its witness McManeus, and Exhibit 5 to the settlement testimony of its witness Pirro. Also on March 2, 2018, DEC filed an Amended Partial Settlement Agreement with NCLM, and the Cities of Concord, Kings Mountain, and Durham.

On March 5, 2018, the Public Staff filed a motion to excuse its witness Lucas from appearing at the expert witness hearing, and to admit his pre-filed testimony into evidence. On the same date, DEC filed a motion to excuse its witness Cowling from appearing at the expert witness hearing, and to admit his pre-filed testimony and exhibits into evidence.[4]

[4] Both witnesses were excused by order of the Chairman from the bench during the expert witness hearing.

On March 20, 2018, Tech Customers filed the supplemental testimony of their witnesses Strunk and Sharon Brown-Hruska, Managing Director, National Economic Research Associates.

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

Franklin: David Watters, Selma Sparks, Kevin Corbin, Donn Erickson, Henry Horton, Fred Crawford, Virginia Bugash, Avram Friedman, Debra Lawley, Bob Boyd, Tamara Zwinak, Margaret Crownover, Janet Wilde, 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 "Gus" 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, 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, Holliday Adams.

This matter came on for the expert witness hearing 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, Hager, Pirro, and Wells. The Public Staff presented the testimony of witnesses McLawhorn, Garrett, Moore, Williamson, Maness, Hinton, Metz, and Floyd. The AGO presented the testimony of witnesses Woolridge and Wittliff. Sierra Club presented the testimony of witness Quarles. NC Justice Center presented the testimony of witnesses Howat and Wallach. 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 the following witnesses, who were excused pursuant to the Orders filed by the Commission on February 27 and March 5, 2018, was copied into the record as if given orally from the stand and their exhibits entered into evidence: DEC witnesses Batson and McGee; Public Staff witness Saillor; CIGFUR witness Phillips; EDF witness Alvarez; NCLM witnesses Fischer, Hunnicutt, and Watkins; Commercial Group witnesses Chriss and Rosa; NCSEA witness Murray; Sierra Club witness Hausman; and Tech Customers witness Strunk. In addition, the parties waived cross-examination of the following witnesses: DEC witnesses Cowling, Diaz,[5] Miller, and Silinski; NC Justice Center witness Deberry; Tech Customers witness Brown-Hruska; and Public Staff witnesses Boswell, Junis, Lucas, McCullar, and Parcell. The pre-filed testimony of each of these witnesses was also copied into the record as if given orally from the stand and their exhibits entered into evidence.

On March 6, 2018, pursuant to Commissioner Clodfelter's request on March 5, 2018, for complete copies of all documents excerpted and introduced as exhibits at the expert witness hearing, the Public Staff filed a complete copy of Exhibit No. 8 to the direct testimony of Public Staff witness Junis, the Electric Power Research Institute's (EPRI) Manual for Upgrading Existing Disposal Facilities. On March 8, 2018, the Public Staff filed complete copies of its De May Cross-Examination Exhibit 11, Moody's Investors Service (Moody's) Regulated Electric and Gas Utilities dated January 24, 2018, and its De May Cross-Examination Exhibit 12, Moody's Duke Energy Carolinas, LLC, Update to Credit Analysis dated October 6, 2017.

On March 9, 2018, DEC filed the revised workpapers of Company witness McManeus, Revised McManeus Stipulation Exhibit 1 – Updated for Hearing, and McManeus Exhibit 4 – Updated for Hearing.

[5] Company witness Diaz was cross-examined on his direct pre-filed testimony. The parties waived cross-examination of witness Diaz's pre-filed rebuttal testimony.

Also on March 9, 2018, Sierra Club filed a complete copy of Exhibit 3 to the direct testimony of its witness Quarles, the 1988 EPA Report to Congress regarding Wastes from the Combustion of Coal by Electric Utility Power Plants. On the same date, the Public Staff filed a complete copy of Exhibit 19 to the direct testimony of its witness Junis, DEC's and DEP's Application for Special Order by Consent dated September 28, 2017. Also on March 9, 2018, the AGO filed the supplemental testimony and exhibits of its witness Woolridge.

On March 12, 2018, pursuant to Commissioner Clodfelter's request at the expert witness hearing on March 7, 2018, DEC filed NPDES permits and groundwater monitoring reports for its North Carolina plants.

On March 14, 2018, DEC and the Public Staff filed a stipulation regarding the pre-filed testimony of Public Staff witness Junis. Pursuant to the stipulation, DEC waived cross-examination of witness Junis, but reserved the right to ask questions based on other parties' cross-examination or Commissioners' questions of witness Junis.

On March 15, 2018, Sierra Club filed a complete copy of its Kerin Cross-Examination Exhibit 4, the 1981 EPRI Coal Ash Disposal Manual.

On March 16, 2018, DEC filed its Confidential Objections to the Public Staff's 156th Set of Data Requests.

On March 19, 2018, the Public Staff filed a complete copy of its Kerin Direct Examination Exhibit No. 2, DEC's 2008 Coal Combustion Products Ten Year Plan.

The Public Staff also filed the second supplemental testimony and exhibits of its witness Boswell and the second supplemental testimony and exhibits of its witness Hinton.

Also on March 19, 2018, DEC filed new versions of the revised workpapers of its witness McManeus, Revised McManeus Stipulation Exhibit 1 – Updated for Hearing, and McManeus Exhibit 4 – Updated for Hearing. The new versions of the workpapers and Revised McManeus Stipulation Exhibit 1 – Updated for Hearing were filed to correct an error identified by the Public Staff in the original versions of those documents which were introduced as exhibits at the expert witness hearing. The new version of McManeus Exhibit 4 – Updated for Hearing provided an update requested during the hearing by CIGFUR reflecting the Company's tax proposal contained in its March 1, 2018 Supplemental Comments filed in Docket No. M-100, Sub 148, and the stipulated capital structure and return on equity agreed to in the Agreement and Stipulation of Partial Settlement filed by DEC and the Public Staff on February 28, 2018.

On March 20, 2018, Tech Customers filed the supplemental testimony of their witnesses Strunk and Brown-Hruska.

Also on March 20, 2018, in response to a question from Commissioner Brown-Bland during the expert witness hearing, the Public Staff filed an overview of the first and most recent sampling dates listed by DEC plant site and supporting data provided by DEC in response to Public Staff Data Request 18A-1.

On March 21, 2018, in response to requests by Commissioner Clodfelter at the expert witness hearing, DEC filed its Response to Request for Groundwater Monitoring Information and confidential board minutes and presentations. Also on March 21, 2018, DEC filed a complete copy of its 2014 Riverbend Steam Station Coal Ash Excavation Plan.

On March 22, 2018, DEC filed confidential and public versions of its FFO/Debt Exhibit referred to by counsel for DEC during the cross-examination of Public Staff witness Hinton. DEC also filed its response to Public Staff Data Request No. 155-3, as requested by Commissioner Clodfelter during the expert witness hearing, Revised Kerin Exhibit 5, as requested by Commissioner Brown-Bland, and Revised Kerin Exhibit 11, as requested by Chairman Finley.

On March 23, 2018, the Public Staff filed the Application by Duke Power Company for Authority to Decrease Its Electric Rates and Charges, dated November 13, 1987, filed in Docket No. E-7, Sub 415, and the Commission's Order Allowing Rates to Become Effective, dated December 4, 1987, issued in Docket Nos. M-100, Sub 113, and E-7, Sub 415. On the same date, the Public Staff filed complete copies of Public Staff Wells Cross-Examination Exhibit No. 6, the Arthur D. Little Study, and Public Staff Wells Cross-Examination Exhibit No. 7, Duke Power Company's 1984 Investigations of Coal Ash Disposal and Its Impact upon Groundwater, Public Staff Wells Cross-Examination Exhibit No. 8, Evaluation of the Effect of Ash Disposal at the Riverbend Plant of Duke Power Company on Groundwater and Surface-Water Quality, and Public Staff Wells Cross-Examination Exhibit No. 9, the transcript of the June 5, 2015 deposition of Thomas

Reeder taken in connection with Duke Energy Progress, Inc. v. N.C. Dep't of Envt. & Natural Res., Division of Water Res., 15-EHR-02581. Also on March 23, 2018, pursuant to the requests of Commissioners Clodfelter and Brown-Bland during the cross-examination of Public Staff witnesses Garrett and Moore during the expert witness hearing, the Public Staff filed the Duke Energy Coal Combustion Residuals Management Program: Phase 2 Reconstruction of Ash Pond Designs Comprehensive Report – W.S. Lee Station, Anderson County, South Carolina, prepared by AECOM and dated January 9, 2018, and the Duke Energy Coal Combustion Residuals Management Program: Phase 2 Reconstitution of Ash Pond Designs Report (Draft) – W.S. Lee Station, Anderson County, South Carolina, prepared by URS and dated December 18, 2014.

On March 26, 2018, pursuant to the request of Commissioner Clodfelter, DEC filed the 1983 Hearing Officer's Report and Recommendations: Groundwater Regulations.

Also on March 26, 2018, Tech Customers filed as late-filed exhibits confidential and public versions of the workpapers supporting the Supplemental Testimony of their witnesses Strunk and Brown-Hruska.

Also on March 26, 2018, pursuant to the request of Chairman Finley for information regarding the number of advanced metering infrastructure (AMI) meters installed by DEC with funds from the American Recovery and Reinvestment Act of 2009, the Public Staff filed the Company's "Lessons Learned

From the Field – 2014 McAlpine Node Refresh," and DEC's response to Public Staff Data Request No. 2-1

On March 28, 2018, in response to the request of Chairman Finley during the expert witness hearing, DEC filed as a late-filed exhibit the Company's current Allowance for Funds Used During Construction (AFUDC) rate. Also on March 28, 2018, DEC filed a number of documents in response to the Commission's request for coal ash impoundment closure plans.

On March 29, 2018, in response to Chairman Finley's request during the expert witness hearing, DEC filed its Report of Customer Inquiry Follow-up from the public hearings conducted in this docket.

On April 2, 2018, DEC filed a spreadsheet containing information regarding its ash basins requested by Commission Clodfelter during the hearing. Also on April 2, 2018, DEC filed as a late-filed exhibit documents regarding its Power Forward Carolinas initiative requested by the Commissioners during the expert witness hearing.

On April 3, 2018, in response to Chairman Finley's request for the IRS rules pertaining to the amortization rate for protected Excess Deferred Income Taxes (EDIT), DEC filed as a late-filed exhibit the definition of "Average Rate Assumption Method " contained in Section 13001(d)(3)(B) of the Tax Act. Also on April 3, 2018, in response to the request of the Commission, DEC filed under seal "Confidential Strategic Projects Sourcing – Ash Basin Sourcing Group Request for Proposal Process Guide."

Also on April 3, 2018, the Public Staff filed the redacted version of Exhibit 7 to the direct testimony of witness Garrett, which was omitted at the time of filing of witness Garrett's direct testimony.

On April 4, 2018, in response to the request of Commissioner Brown-Bland during the expert witness hearing, DEC filed confidential contracts for coal ash excavation and hauling at the Dan River site.

On April 5, 2018, also in response to requests during the expert witness hearing by Commissioner Brown-Bland, DEC filed confidential contracts for coal ash excavation and hauling at the Riverbend and Sutton sites and estimated ash basin quantities for 2006-2017.

On April 6, 2018, DEC filed its response to a question asked by Commissioner Clodfelter during the expert witness hearing regarding whether closure costs associated with the Company's non-CCR and CAMA regulated sites were included in the asset retirement obligation (ARO). On the same date, DEC filed a late-filed exhibit responding to a question posed by Commissioner Clodfelter to DEC witness Hager during the expert witness hearing regarding the extent to which a planned change in the minimum system study methodology would impact the customer charge in the Grid Rider.

On April 10, 2018, pursuant to the Stipulation, the Public Staff filed the affidavit of its witness Boswell presenting the results of the Public Staff's investigation of the final cost amounts for the W.S. Lee Combined Cycle plant (Lee CC) to be included in rate base and the Public Staff's final recommendations to update salaries and wages. On the same date, also in response to the Stipulation, DEC filed the affidavit of its witness Miller attesting to the date its Lee CC plant was placed in service.

On April 16, 2018, in response to a request made by Commissioner Clodfelter during the expert witness hearing for information on updates to DEC's ash basin closure plan, the AGO filed its Response to Commission Request and Motion to Admit AGO Late-Filed Exhibit 1.

On April 19, 2018, Company witness McManeus and Public Staff witness Boswell filed corrected exhibits and schedules. Also on that date, the Commission entered an Order requiring DEC to file as a late-filed exhibit a list of DEC's 15 "Areas of Vulnerability" as discussed in the Power Forward Executive Technical Overview (Simpson Rebuttal Exhibit 2).

On April 23, 2018, DEC filed a late-filed exhibit in response to the Commission's April 19, 2018 Order.

On April 24, 2018, the Commission issued an Order granting the AGO's motion to admit AGO Late-Filed Exhibit 1.

On April 24, 2018, DEC filed a late-filed exhibit regarding the Atlantic Coast Pipeline in response to a question from Commissioner Patterson during the expert witness hearing.

On April 26, 2018, EDF filed its post-hearing brief.

On April 26, 2018, the Public Staff filed its Motion to Add Late-Filed Exhibit to the Record, and the attached Maness Late-Filed Exhibit, setting forth the Public Staff's and DEC's respective final positions regarding coal-ash-related revenue requirements.

Based upon consideration of the pleadings, testimony, and exhibits received into evidence at the hearings, the Stipulation, 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 the Commission. The Company is engaged in the business of generating, transmitting, distributing, and selling electric power to the public in a broad area in western North Carolina except for an area in western North Carolina in and around the City of Asheville. DEC is a wholly-owned subsidiary of Duke Energy Corporation, and its office and principal place of business are located in Raleigh, 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 G.S. 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.[6]

The Application

5. By its Application and initial direct testimony and exhibits, DEC 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%. The Company also requested a Grid Rider to recover an additional $26 million, which has the effect of an additional 0.8% increase. On December 15, 2017, the Company filed supplemental direct testimony and exhibits. On December 18, 2017, the Company filed Revised Supplemental testimony. On January 16, 2018, the Company filed second supplemental direct testimony and exhibits. The effect of the Company's supplemental filings was to change its proposed annual revenue increase to $694 million.

[6] Pursuant to the Stipulation, the costs of the Lee CC were updated through February 28, 2018.

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 (Stipulating Parties) jointly filed an Agreement and Stipulation of Partial Settlement (Stipulation). On February 28, 2018, DEC entered into a Partial Settlement Agreement with NCLM and the Cities of Concord and Kings Mountain, and on March 2, 2018, DEC filed an Amended Partial Settlement Agreement between DEC, NCLM and the Cities of Concord Kings Mountain, and Durham (NCLM Partial Settlement).

8. Both the Stipulation and the NCLM Partial Settlement are the product of the "give-and-take" in settlement negotiations between the Stipulating Parties, as well as between DEC, NCLM, and the Cities of Concord, Kings Mountain, and Durham. Further, the Stipulation and the NCLM Partial Settlement are material evidence, and are entitled to be given appropriate weight by the Commission, along with all competent and material evidence in the record.

9. The Stipulation resolves only some of the disputed issues between the Stipulating Parties. The Stipulating Parties did not reach an agreement regarding cost recovery of the Company's CCR costs, the recovery amortization period and return during the amortization period, allocation issues associated with

CCR costs, and the amount of ongoing CCR costs to be included in rates. They also did not agree on whether it is appropriate to allow a return on the unamortized balance during the amortization period for the Lee Nuclear project; the status of the Company's NDTF and the Pubic Staff's proposal to adjust nuclear decommissioning expense; the methodology for calculating customer usage through December 2017; the manner in which the Tax Act should be addressed in this case; the amount of annual depreciation expense and associated accumulated depreciation to be used for ratemaking; whether a Grid Rider should be adopted in this proceeding; and the amount of the BFC. Although the Stipulating Parties agreed that the Company's proposed JRR generally complies with the Commission's guidelines adopted in Docket No. E-100, Sub 73, they disagreed on (a) whether companies involved in the transportation or preservation of a raw material or a finished product (e.g., pipeline customers) should qualify; and (b) how, or if, the JRR should be funded after the expiration of the initial year's $3.5 million shareholder contribution. These issues were left for resolution by the Commission and are addressed later in this Order.

<u>Adjustments to Cost of Service</u>

10. The Stipulation provides for certain accounting adjustments, which are set out in detail in Revised McManeus Stipulation Exhibit 1 – Updated for Hearing and Boswell Second Supplemental and Stipulation Exhibit 1 as "Settled Issues". The Stipulating Parties agreed that settlement on those issues will not be used as a rationale for future arguments on contested issues brought before the

Commission. For the present case, the accounting adjustments outlined as the "Settled Issues" are just and reasonable to all parties in light of all the evidence presented.

11. The Stipulation provides that the State EDIT collected by DEC 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.

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

12. The Stipulating Parties agree that the revenue increase 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.

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

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

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

16. The rate increase 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.

17. 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.

18. 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 increased rates.

19. 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 maintain a strong credit rating with its customers' need to pay the lowest possible rates.

20. 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 G.S. 62-133, and are fair to DEC's customers generally and in light of the impact of changing economic conditions.

Requested CCR Fuel Costs

21. G.S. 62-133.2(a1)(9) allows electric public utilities to recover the net gains or losses resulting from the sales by the electric public utility of by-products produced in the generation process to be recovered through the fuel adjustment clause.

22. Paragraph III.P. of the Stipulation provides that given the Commission's Findings of Fact Nos. 57-59 and associated conclusions in its Order entered February 23, 2018 in Docket No. E-2, Sub 1142 (2018 DEP Rate Order), the Company withdraws its request to recover certain 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.

23. The beneficial reuse of CCRs, in and of itself and absent an actual sale, does not constitute the sale of a by-product under G.S. 62-133.2(a1)(9).

24. The contract between DEBS on behalf of DEC and Charah, Inc., for the excavation, transportation, and placement of ash from the Riverbend Plant to the Brickhaven facility is a contract for services and not for the sale of a by-product under G.S. 62-133.2(a1)(9).

Base Fuel Factor and Coal Inventory

25. The North Carolina retail base fuel expense for this proceeding is $1,087,140,814, and the following base fuel and fuel-related cost factors are just and reasonable to all parties in light of all the evidence presented for purposes of this proceeding (amounts are cents per kilowatt-hour (kWh), excluding regulatory fee): 1.7828 cents/kWh for residential customers; 1.9163 cents/kWh for general service and lighting customers; and 2.0207 cents/kWh for industrial customers. Billed fuel rates shall be adjusted to reflect changes to DEC's fuel rates approved by the Commission in Docket No. E-7, Sub 1129 that were effective on September 1, 2017.

26. 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 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.

Quality of Service and Service Regulations

27. Paragraph IV.J. of the Stipulation provides that the overall quality of electric service provided by DEC is adequate. This provision of the Stipulation is just and reasonable.

28. The proposed amendments to DEC's Service Regulations are reasonable and should be approved.

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.

Cost of Service Allocation Methodology

30. 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. For purposes of this proceeding, 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 allocation methodology are just and reasonable to all parties in light of all the evidence presented.

31. The Company shall file annual cost of service studies based on both the SCP and summer/winter coincident peak and average (SWPA) methodologies.

Rate Design

32. For the purposes of apportioning and assigning the approved increase in base non-fuel and base fuel revenues between the North Carolina customer classes in this proceeding, the apportionment and rate design principles presented by DEC witnesses Pirro and Cowling, subject to the modifications set out in Section IV.E. of the Stipulation, and the NCLM Partial Settlement are just reasonable, appropriate, and nondiscriminatory.

33. The Company shall implement the rate design proposed by witnesses Pirro and Cowling, as well as the specific modifications set out in Section IV.E. of the Stipulation and the NCLM Partial Settlement.

Acceptance of Stipulation

34. The Stipulation and the NCLM Partial 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 NCLM Partial Settlement are just and reasonable to all parties to this proceeding and serve the public interest. Therefore, the Stipulation and the NCLM Partial Settlement should be approved in their entirety.

Lee Nuclear Project

36. The costs incurred for the architectural and engineering design of a visitors' center should be disallowed on the basis that under the dictates of the Commission's August 5, 2011 Order in Docket No. E-7, Sub 819, the costs did not directly support the combined operating license application (COLA) process at the Nuclear Regulatory Commission (NRC) and were not necessary to maintain the status quo at that time.

37. As all substantive work at the Lee Nuclear Project had ceased and been suspended by December 31, 2017, no further accrual of AFUDC should be allowed after that date.

38. DEC should be allowed to recover all costs of the Lee Nuclear Project, except as addressed in Findings of Fact 36 and 37 above, through amortization over a period of 12 years, with no return on the amortized balance.

Nuclear Decommissioning Trust Fund

39. The funding model that ensures that sufficient funds are available to decommission the Company's nuclear units indicates that the Company's NDTF is overfunded by approximately $2.4 billion. The normal operation of the funding model indicates that the Company's nuclear decommissioning expense should be reduced by $29.1 million.

40. The Company's ability to reduce its NDTF prior to actually using the funds for decommissioning is largely restricted.

41. The Company's annual revenue requirement shall be reduced by $29.1 million (exclusive of tax effects) to advance the return to ratepayers of the NDTF overfunding. In conjunction with this reduction in the annual revenue requirement, the Company shall establish a regulatory asset for the difference between the credit nuclear decommissioning expense recommended by witness Hinton and the zero amount of nuclear decommissioning expense proposed by the Company, adjusted appropriately for income tax effects.

<u>Depreciation</u>

42. Use of a 0% contingency for future "unknowns" in the estimate of future terminal net salvage costs is reasonable in this case.

43. Inflating the estimated terminal net salvage costs to the year 2023 is reasonable in this case.

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

45. Use of an average service life of 17 years for the new AMI meters is reasonable in this case.

46. It is just and reasonable for the remaining costs of the meters replaced due to the expedited deployment of AMI meters to be recovered over 15.4 years.

47. It is reasonable and appropriate to approve the use of the Public Staff's proposed depreciation rates as shown on Exhibit RMM-1.

Power Forward and the Grid Rider

48. The projects comprising DEC's Power Forward initiative are not unique and are no different than projects the Company performs and should perform in the ordinary course of its operations to meet its statutory obligation to provide adequate and reliable service to its customers.

49. It is not appropriate to establish a rider or a regulatory asset relating to recovery of the costs of the Power Forward initiative.

CCR Basin Closure Costs

50. Prior to making a determination to transport and dispose of coal ash off-site, it is appropriate for DEC to conduct a full evaluation of on-site management options.

51. The moratorium in Section 5.(a) of S.L. 2014-122 did not prohibit the consideration or construction of on-site greenfield landfills.

52. DEC did not sufficiently evaluate on-site greenfield landfill options at the Dan River Site that could have been reasonably built and operated to comply with the closure deadlines in Section 3.(b) of S.L. 2014-122.

53. The decision to transport ash from Riverbend to the Brickhaven structural fill facility, as opposed to managing all of the coal ash at other Duke owned-facilities, was not reasonable or prudent.

54. DEC's decision to transport ash from Riverbend to the R&B Landfill in Homer, Georgia, in 2015, as opposed to transporting the coal ash to the on-site landfill at Marshall, was not reasonable or prudent.

55. To reduce costs to customers, DEC should maximize the use of existing and new utility-owned landfill facilities when they are available at lower costs than third party off-site disposal options.

56. DEC's decision to select the Buck facility for its third beneficiation site resulted in significantly higher closure costs than what would have been otherwise applicable to the Buck facility.

57. DEC's decision to immediately excavate the ash from the Inactive Ash Basin at the W.S. Lee facility in South Carolina, rather than following the guidance provided by its engineering consultants to correct maximum pool storage and liquefaction issues, resulted in an expenditure of funds for off-site hauling and transportation that was not reasonable or prudent.

58. DEC has not yet submitted proposed closure plans for the impoundments at Belews Creek, Allen, Cliffside, and Marshall for review and approval by the North Carolina Department of Environmental Quality (DEQ) pursuant to G.S. 130A-309.214(a)(2) and (3). As such, the Commission does not take any position at this time with regard to the prudence of the closure plans at those facilities.

CCR Cost Deferral

59. 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 the DEC 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.

60. 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.

61. 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%.

62. 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

63. 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 17 coal ash basins at the Company's coal-fired power plants. Since its last rate case, DEC has incurred significant costs to comply with these new legal requirements.

64. On a system basis, the actual coal ash basin closure costs DEC has incurred during the period from January 1, 2015, through December 31, 2017, amount to $725,208,000. The appropriate and reasonable system amount of disallowances to deduct from this spent amount is $100,051,000. 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, net of the appropriate and reasonable disallowances, amount to $470,652,000, including carrying costs of $51,069,000 for the period January 2015 through April 2018. The actual coal ash basin closure costs incurred by DEC, less the

disallowances, are reasonable and it is appropriate to allow recovery of these costs through rates, subject to the next Finding of Fact.

65. There is substantial evidence in light of the whole record showing that DEC's coal ash disposal practices have resulted in extensive violations of environmental laws and regulations. Because of these violations, as well as the magnitude and extraordinary nature of the coal ash remediation costs, it is fair and reasonable to equitably share the coal ash remediation costs, net of disallowances, between ratepayers and investors, pursuant to G.S. 62-133(d).

66. In the circumstances of this case, an equitable sharing would be for approximately 49% of the costs to be borne by ratepayers, and 51% of the costs to be borne by investors. This equitable sharing is to be achieved by amortizing the deferred coal ash costs over a 25-year period, with no return on the unamortized balance. This allows DEC recovery of all its deferred coal ash costs, but not a return on those costs while they are being amortized. Given the time value of money at DEC's authorized rate of return, the effect is a sharing of the costs in the amounts specified herein. The resulting appropriate annual North Carolina retail amortization expense is $18,882,000.[1] When combined with the removal of the unamortized balance of deferred coal ash costs from rate base, the

[1] This amount is calculated by dividing $470,652,000 by 25 years, and then adding $56,000 to the result. The $56,000 represents additional carrying costs calculated by the Company that the Public Staff did not contest.

reduction in the Company-proposed revenue requirement related to deferred coal ash costs is approximately $120.4 million.

67. [***PUBLIC STAFF'S LESS-PREFERRED ALTERNATIVE TO THE PRECEDING FINDING OF FACT. THIS ALTERNATIVE FINDING ASSUMES NO SPECIFIC DISALLOWANCES AT ALL, AS WELL AS NO EQUITABLE SHARING.***] On a system basis, the actual coal ash basin closure costs DEC has incurred during the period from January 1, 2015, through December 31, 2017, amount to $725,208,000. Allocated to N.C. retail operations in accordance with the findings in this order, this amount totals $486,705,000. With N.C. retail carrying costs of $58,996,000 for the period January 2015 through April 2018 added, the total deferred amount is $545,701,000. Under the present facts, a mismanagement penalty in the approximate sum of $72.3 million is appropriate with respect to DEC's CCR remediation expenses accounted for the ARO established 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 $72.3 million penalty by amortizing the $545,701,000 over five years with a return on the unamortized balance and then reducing the resulting annual expense by $14.46 million for each of the five years.

68. DEC further proposes that it recover on an ongoing basis $200.6 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 approved. Rather, DEC is authorized to record its future CCR costs, beginning on January 1, 2018, in a deferral account until its next general rate case.

Provisional CCR Cost Recovery

69. DEC's recovery of the CCR costs approved in this proceeding is through provisional rates.

CCR Allocation Guidelines

70. 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.

71. 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

72. It is appropriate 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.

This reporting requirement shall apply even if the case is appealed to a higher court.

73. 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.

74. If 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.

Job Retention Rider

75. 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 or a finished product" should not be eligible to participate in a JRR.

76. The Company's recovery of the JRR revenue credits should be reduced by $4.5 million each year the JRR is in effect to recognize the benefit to shareholders of the JRR.

Basic Facilities Charge

77. The BFC should be set an amount to reflect cost causation and provide customers with appropriate cost signals.

78. Setting the BFC at an artificially low rate will over-compensate energy efficiency and distributed generation for the costs avoided by their actions. An artificially low BFC will shift customer-related costs to the energy rates, which results in unreasonable cross-subsidization.

79. Setting the BFC at a level that recovers no more than 25% of the proposed increase for an individual customer class is just and reasonable for this proceeding and strikes an appropriate balance that provides rates that more clearly reflect cost causation.

Customer Growth and Usage

80. The Public Staff's methodology to calculate customer growth and usage is appropriate for use in this proceeding.

81. The appropriate kWh sales adjustment related to customer growth and usage for the 12-month test period through the update period ending December 31, 2017, is 156,057,311 kWh.

82. The revenue adjustment related to customer growth and usage for the test period through the update period ending December 31, 2017, is $16,308,523.

Tax Act

Federal Income Tax Expense/Federal EDIT/Accelerated Depreciation

83. The Company's revenue requirement shall be adjusted to incorporate the effects of the changes in federal income tax related to the Tax Act, including the effects of the reduction of the federal income tax from 35% to 21% on the Company's ongoing income tax expense.

84. The Company's protected Federal EDIT should be amortized over a period of time equal to the expected lifespan of the plant, property and equipment with which they are associated, in accordance with the normalization rules of the United States Internal Revenue Service.

85. The Company's unprotected Federal EDIT should be returned to ratepayers through a rider over a period of five years. No distinction should be drawn between taxes described by DEC as being "related to" property, plant or equipment and those that are not so related.

86. The Company's proposal to record $200 million per year in either accelerated depreciation, the costs of closing coal ash basins, or other accounts or cost categories is not approved.

Effect of Return of Federal EDIT on DEC's Credit Metrics

87. Returning Federal EDIT to customers as otherwise provided in this Order will not unreasonably or significantly affect DEC's ability to compete in the market for capital funds on terms that are reasonable and fair to DEC's customers and DEC's investors.

Accounting for Deferred Costs

88. 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

89. 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.

90. 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.

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

92. The appropriate revenue requirement for the first five years should be reduced by the Federal EDIT Rider decrement of $224.365 million.

<u>Just and Reasonable Rates</u>

93. 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 DEC'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, DEC's verified Application and Form E-1, the testimony of DEC witnesses Fountain and McManeus, 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, including a rate of return on common equity of 10.75%. The Company also requested a Grid Rider to recover an additional $26 million, which has the effect of an additional 0.8% increase. On December 15, 2017, the Company filed supplemental direct testimony and exhibits. On December 18, 2017, the Company filed Revised Supplemental testimony. On January 16, 2018, the Company filed second supplemental direct testimony and exhibits. The effect of the Company's supplemental filings was to change is proposed annual revenue increase to $694 million. In its rebuttal testimony filed on February 6, 2018, the Company modified its requested increase to $700.6 million. The Company's requested increase was reduced in the Stipulation filed on February 28, 2018, to a requested increase of $478.5 million (a base rate increase of $538.5 million reduced by a four-year annual State EDIT rider of $(60 million)). 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. These amounts are reflected in the direct, supplemental, and rebuttal testimony and exhibits filed by Company witness McManeus.

In his direct testimony, Company witness Fountain described why DEC is seeking a rate increase. He testified that recent work to maintain and modernize DEC's electric system, efforts to generate cleaner power including nuclear development, responsibly manage and close coal ash basins, and continually enhance service to customers has made it necessary for DEC to request a base rate increase. In addition, DEC also 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. (T 6 p 162)

Witness Fountain further testified that major generating plant projects, nuclear development work, grid improvements and modernization, and additions and plant-related expenses, as well as improvements to the customer information system (CIS) and additional funding for vegetation management, account for the majority of the total additional requested annual revenue requirement. The remainder of the requested base rate adjustment is to recover costs related to environmental requirements associated with the mandated closure of ash basins and other net ongoing operational costs, offset by certain regulatory liabilities and decreases in rate base. (T 6 p 163)

Witness Fountain described the various investments in facilities, equipment and operations driving the Company's requested increase. An example is the Lee CC. The Company has also added two solar facilities and completed the relicensing for the hydro stations on the Catawba-Wateree. (T 6 pp. 166-167) He also described DEC's request to recover the costs of the cancelled Lee Nuclear Project. (T 6 pp. 167-168) In addition, the Company seeks recovery of the costs to deploy AMI and the costs of implementing a new CIS, called "Customer Connect". (T 6 p 168)

Witness Fountain also described the Company's efforts to comply with State and federal laws and regulations regarding the management and closure of ash basins. The Company seeks to recover these compliance expenses over a five-year period. (T 6 p 169)

Witness Fountain stated that the cost increases proposed by the Company are partially offset by the return of a deferred State tax liability to customers over the next five years. (T 6 p 170) According to witness Fountain, even with the rate adjustment, customers will continue to pay rates below the national average and competitive with other utilities in the region. (T 6 p 178)

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-9

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 NCLM Partial Settlement.

The Public Staff and DEC filed the Stipulation on February 28, 2018. The Stipulation was based on the same test period used by the Company in its

Application, with updates. The Company and NCLM and the Cities of Concord and Kings Mountain filed a Partial Settlement Agreement on February 28, 2018, and filed an Amended Partial Settlement on March 2, 2018, which also added the City of Durham as a stipulating party.

Witness Fountain explained that the Stipulation resolves many, but not all of the revenue requirement issues between the Company and the Public Staff. (T6 p 218)

Witness Fountain summarized the Stipulation as follows:

1. Capital Cost and Structure - The Stipulating Parties have agreed to a rate of return on equity of 9.90%, based upon a capital structure containing 52% equity and 48% debt, as described by witnesses Hevert and De May, and a cost of debt of 4.59%. The resulting weighted average rate of return is 7.35%.

2. Distribution Vegetation Management – The Public Staff and the Company have agreed on the amount of distribution vegetation management expenses in an annual amount of $62.6 million on a total system basis. This amount reflects rising contractor rates that are affecting the Company's costs in effectuating its trim cycles. 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.

3. Lee CC – The Public Staff and the Company have agreed upon the appropriate level of ongoing operation and maintenance (O&M) and deferred

expenses for Lee CC. The parties note that the Lee CC is almost complete but not anticipated to come online until later in March, and the Stipulation contains a plan to hold the record open solely for the purpose of verifying the amounts to be included in the rates and confirmation that the plant is operational.

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

5. Other Adjustments – Revenue requirement reductions were also agreed upon in the Stipulation for Aviation, 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-Piedmont merger costs to achieve, salaries and wages, and DEBS allocations. 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. The Stipulating Parties also agreed on the return of State EDIT to customers through a four-year rider.

6. JRR – The Stipulating Parties have also agreed to resolve the Company's JRR proposal to be described within the Stipulation filed with the Commission, except for two remaining items to be decided upon by the Commission as described in the Stipulation.

7. 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 BFC, which is not resolved by the Stipulation).

8. Recover 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. 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. (T 6 pp 218-21)

Witness Fountain testified 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 customers. (T 6 p 222)

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. (T 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. (T 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. (T 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. (T 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. (T 26 p 890)

As the Stipulation and the NCLM Partial Settlement have not been adopted by all of the parties to this docket, their 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 a court to subject the Commission's Order adopting the provisions of a non-unanimous stipulation to a "heightened standard" of review. CUCA II, 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court held that Commission approval of the provisions of a non-unanimous 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 NCLM Partial Settlement, and finds and concludes that the Stipulation and the NCLM Partial 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.

Based on the foregoing, the Commission finds and concludes that the Stipulation and the NCLM Partial Settlement are material evidence to be given appropriate weight in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-11

The evidence supporting these findings of fact and conclusions is found in the verified Application and Form E-1 of DEC, the testimony and exhibits of the Company witnesses, the testimony and exhibits of the Public Staff witnesses, the testimony and exhibits of the intervenors, the Stipulation, and the entire record in this proceeding.

The Stipulation resolved a number, but not all, of the issues in dispute between the parties. DEC witness McManeus presented exhibits showing the monetary effect of the various issues (accounting adjustments and otherwise) addressed in the Stipulation. 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 of this Order are discussed in more detail below.

Adjust Vegetation Management

In its Application, the Company proposed to increase its vegetation management plan costs for an increase in the frequency of trimming and herbicide application, and the continuation of other vegetation management practices such as hazard tree cutting. The Company also requested an increase to reflect a 7% increase in contractor vegetation management production labor costs. Company witness Simpson testified that vegetation management is a critical component of the Company's power delivery operations and the continued effort to drive performance for customers' benefit. (T 16 p 100) He stated that the Company has included a pro forma adjustment related to an expected $15.8 million increase in system expenditures for vegetation management. (T 16 p 102)

The Public Staff recommended approval of part of the recommended increase. Public Staff witness Williamson explained that the Public Staff agreed that costs should be adjusted to reflect the 7% increase in contractor vegetation management production costs; however, the Public Staff excluded $8.5 million of the Company's request because that amount represented the cost of addressing vegetation management backlog. (T 22 p 45) Public Staff witness Boswell testified that the Public Staff's adjustment to distribution vegetation management is calculated based on the production costs incurred during the test period and adjusted to reflect the actual cost increases for which the Company has signed contracts. (T 26 p 617)

In his rebuttal, Company witness Simpson requested that the Commission reject the adjustment recommended by the Public Staff and approve the Company's vegetation management request, especially given the proof of increased contract rates and requested mileage adjustment to fund the Company's vegetation management plan. (T 23 p 159)

The Stipulation provides that the Company should be allowed to recover distribution vegetation management costs in an annual amount of $62.6 million, for purposes of settlement, on a total system basis, and this figure includes acceptance of the Public Staff's downward adjustment related to untrimmed, backlog miles as described by Public Staff witnesses Williamson and Boswell. For the purpose of complying with the Company's current vegetation management program, the Company commits to eliminate completely the 13,467 miles of existing backlog as of December 31, 2017 (as identified in the testimony of Public Staff witness Williamson) ("Existing Backlog") within five years after the date rates go into effect in this proceeding, and the Company additionally commits to spending the necessary amount on an annual basis to trim its annual target distribution miles under its 5/7/9 Plan. Notwithstanding the Company's obligation to provide safe, adequate, and reliable electricity service to its customers, fulfilling these commitments will be sufficient to return the Company's distribution line miles to a state so that thereafter vegetation can be trimmed on the following schedule: trimming all 2,180 old urban miles every five years, all 7,831 mountain miles every seven years, and all 41,603 other miles every nine years (5/7/9 Plan). In addition, DEC agrees 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. All data reported will be categorized by circuit type (e.g., old urban, mountain, other). The Company further agrees 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. This provision shall not be construed to prohibit the Stipulating Parties from presenting evidence or arguments concerning vegetation management in the context of the Company's request for the Grid Rider.

Adjust 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. During the test year, Duke Energy acquired Piedmont Natural Gas (PNG), and the merger was approved by the Commission 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 on a going-forward basis. As a result, witness Boswell made an adjustment to reflect the fact that O&M expenses allocated to DEC from DEBS will be less going forward. (T 26 p 595) In the Stipulation, the Company accepted the Public Staff's recommended adjustment regarding the DEBS to DEC allocation as set forth in the supplemental testimony of witness Boswell.

Customer Connect Project (CCP)

Company witness Fountain testified that the current customer information system is more than 30 years old and needs replacement. (T 6 p 170) Company witness Hunsicker testified that the Company's business and customer needs are very different than they were when the original system was constructed, and have moved past the point where modular "bolt on" systems or modular upgrades are effective. (T 18 pp 255-56) She testified that DEC's current system must be replaced to provide a more stable platform, greater flexibility, ease of configuration, and ability to offer more advanced rates and billing structures, as well as services to customers, than what is currently possible. (T 18 p 260) Witness Hunsicker stated that the CCP will begin analysis and design in January 2018, and is currently planned to be placed in service for DEC in 2022. (T 18 p 262) Specifically for DEC, the costs of the improvements will be between $220-$230 million, as shown on Hunsicker Exhibit 1. (T 18 p 263)

Public Staff witness Floyd testified that while the Public Staff is generally supportive of deploying CCP, it was not used and useful as of December 31, 2016. According to DEC, the CCP is likely to become only partially used and useful as of the end of 2018. The full capabilities of the CCP are not expected to be used and useful in the DEC service territory until 2022. The Company is still uncertain exactly when DEC will be able to fully utilize the various components of the CCP. (T 23 pp 80-81) Public Staff witness Boswell made an adjustment to remove the forecasted O&M amounts the Company plans to spend between 2018 and the in-service date because the system is in the analytics stage and is currently non-functional. Witness Boswell testified that the Public Staff does not oppose the approval of a regulatory asset for the CCP. (T 26 pp 597-98)

In her rebuttal, Company witness Hunsicker disagreed with witness Boswell as to the status of CCP. According to witness Hunsicker, the Company has only asked for the level of O&M necessary to deploy the capital for the program. She also testified that the Company will be delivering new capabilities to customers every year of the program beginning in 2018. She also testified that the forecasted expenses for CCP are known and measurable. (T 18 pp 268-72)

The Stipulation provides that the incremental operating expenses for the CCP should be removed from the Company's revenue requirement as recommended by the Public Staff. Instead, the Company should be authorized to establish a regulatory asset to defer and amortize expenses associated with the CCP. The Company should be allowed to accrue and recover AFUDC on the regulatory asset until the DEC Core Meter-to-Cash release (Releases 5-8) of the CCP goes into service or January 1, 2023, whichever is sooner, at which time a 15-year amortization shall begin. 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 on December 31 of each year or until CCP is fully implemented, whichever is later.

Aviation

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 her staff. The Public Staff recommended that certain expenses allocated to DEC be removed due to the nature of the flights involved. (T 26 pp 591-92) The Stipulation removes 50% of the corporate aviation O&M expense requested by the Company.

Executive Compensation

In its initial filing, the Company removed 50% of the compensation of the top four executives. Public Staff witness Boswell recommended an adjustment to remove 50% of an additional executive, to reflect the fact that the additional executive's duties and compensation encompass a substantial amount of activities that are closely linked to shareholder interests, just as in the case of the other four executives. The Public Staff also recommended an adjustment to remove 50% of the benefits associated with these top five executives. (T 26 p 587)

In the Stipulation, the Company accepts the Public Staff's adjustments to remove 50% of the compensation of the five Duke Energy executives with the highest amounts of compensation, and to remove 50% of the benefits associated with those five executives.

Outside Services

Public Staff witness Boswell testified that the Public Staff's investigation of the costs for outside services revealed charges that were related to legal services for coal ash and groundwater issues related to coal ash. She removed these expenses from O&M. In addition, witness Boswell found certain expenses that were allocated to DEC by DEBS that should have been directly assigned to other jurisdictions and recommended their removal. (T 26 pp 592-93) In its rebuttal filing and in the Stipulation, the Company agreed to remove certain costs associated with outside services as recommended by the Public Staff. This amount does not include costs incurred for certain legal services related to coal ash, which are included in the Unresolved Issues.

Duke-Piedmont Costs to Achieve

Public Staff witness Boswell testified that on September 29, 2016, in Docket Nos. E-7, Sub 1100, E-2, Sub 1095, and G-9, Sub 682, the Commission issued its

Order Approving Merger Subject to Regulatory Conditions and Code of Conduct (Merger Order), which approved the merger between Duke Energy Corporation and PNG. Ordering paragraph 7(b) of the Merger Order, which addresses the ratemaking treatment of costs incurred to achieve the merger, states (emphasis added):

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

On October 4, 2017, Duke Energy Corporation filed a letter indicating that both it and PNG accepted and agreed to all the terms, conditions, and provisions of the Merger Order, including the Regulatory Conditions and Code of Conduct. During the test year in this case, DEC has 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. (T 26 pp 593-94)

Witness Boswell stated that since the Merger Order states in ordering paragraph 7(b) that DEC shall only be allowed to recover the capital costs associated with achieving merger savings, such as system integration costs, the Public Staff has removed the $6.5 million of O&M expenses that DEC identified as systems and transitions costs to achieve the merger that were included in its North Carolina retail operating expenses in this case.

On rebuttal, witness McManeus testified that the Merger Order did not specifically address cost recovery for operating expenses associated with achieving merger savings. (T 6 p 326) In the Stipulation, the Company accepted the Public Staff's proposed adjustment to remove costs to achieve the Duke-Piedmont merger.

Lee CC

In his direct testimony, Company witness Fountain testified that the addition of the Lee CC further increases the Company's use of natural gas at a time when pricing has been favorable. He stated that the Lee CC features state-of-art technology for increased efficiency and significantly reduced emissions. (T 6 p 167) In her direct testimony, Company witness McManeus included an adjustment to rate base to include the Lee CC. She also included an adjustment to reflect a three-year amortization of the deferred costs related to the addition to plant in service for the project. (T 6 p 256)

In her direct testimony, Public Staff witness Boswell recommended several adjustments to expenses. First, she recommended reducing the estimated incremental materials and supplies inventory for the plant. She also recommended removing the Lee CC O&M expenses because the amount provided by the Company was an estimate, not actual O&M expenses needed to operate the plant.

Finally, she reduced the depreciation rate based on the recommendation of Public Staff witness McCullar. (T 26 pp 580-81).

Witness Boswell also incorporated several adjustments to the Lee CC deferral calculation. After incorporating the adjustments to the Lee CC plant additions calculation, she included only three months of deferral costs and adjusted the Company's pre-tax rate of return. In addition, she recommended that the Lee CC deferral costs be recovered through a levelized amortization over a five-year period. (T 26 p 582)

In rebuttal, Company witness McManeus stated that the Company agreed with witness Boswell's adjustment reducing the level of materials and supplies inventory. (T 6 p 308)

In the Stipulation, the Company and the Public Staff acknowledged that the Lee CC was almost complete, but not anticipated to come online until later in March, 2018. The parties agreed to the following:

1. The Company withdraws its adjustment to include incremental O&M expenses for the Lee CC and the Public Staff withdraws its displacement adjustment for Lee CC. The Parties therefore agreed that the appropriate level of ongoing O&M expense is $0.

2. The appropriate amortization period for the deferred expenses is four years.

3. It is appropriate to hold the record open until March 23, 2018, for the sole purpose of allowing Company to 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 increase or decrease approved by the Commission. The Public Staff will utilize these amounts to work with the Company to file with the Commission, by April 6, 2018, the 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.

4. It is appropriate to hold the record open until April 22, 2018 for the sole purpose of allowing the filing by the Company of an affidavit indicating that the plant has closed to service for operational and accounting purposes and that is used and useful for the benefit of customers.

On April 10, 2018, the Company filed the affidavit of Joseph A. Miller, Jr. notifying the Commission that the Company commenced commercial operation of the Lee CC plant on April 4, 2018. On that same date, Public Staff witness Boswell filed an affidavit stating that DEC had provided the Public Staff with the final costing of the Lee CC plant in accordance with the Stipulation and that the Public Staff had audited the final costing information. With her affidavit, witness Boswell filed updated recommendations regarding the Lee CC plant and expense related items in her Boswell Third Supplemental and Stipulation

Exhibit 1. On April 19, 2018, witness Boswell filed corrected Lee CC plant and expense related amounts.

Incentives

In her direct testimony, Public Staff witness Boswell described DEC's incentive plans. According to witness Boswell, DEC offers two incentive plans to its employees: the Short-Term Incentive Plan (STIP) and the Long-Term Incentive Plan (LTIP). The STIP is offered to all employees, including executives. The LTIP is offered to employees at the Director level and above. Approximately 700 employees of Duke Energy Corporation qualify for the LTIP.

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

Witness Boswell stated that the Company's payout of STIP is based on the achievement of targets at minimum, target, and maximum levels. During the test year, the Company included an adjustment to reduce the STIP from the 2016 payout level to the 2017 target level. With regard to LTIP, the Company made an adjustment to remove the 2016 accruals and replace them with 2017 target accruals.

Witness Boswell adjusted the allowable costs of STIP to exclude the incentive accruals that were based on the EPS metric. She stated that the Public Staff believes that the incentives related to EPS should be excluded because they provide a direct benefit to shareholders rather than to ratepayers. It should be further noted that the EPS portion of the STIP only accounts for 30% of the non-executive level employees accrual, and 50% of the executive level employees accrual.

Witness Boswell also adjusted the allowable LTIP costs to exclude the Performance Shares, which include the EPS and TSR metrics. She stated that the Public Staff believes that the incentives related to EPS and TSR should be excluded because they provide a direct benefit to shareholders rather than to ratepayers. The Company's BOD minutes depict a direct link and benefit between the Company's goals and shareholder's interests. Therefore, these costs should be borne by shareholders. (T 26 pp 589-91)

In his rebuttal testimony, Company witness Silinski testified that these proposed adjustments are inappropriate and should be rejected by the Commission. He testified that Duke Energy's overall compensation philosophy is to target total compensation of base pay and incentives, including both short- and long-term, at the median of the market when compared to peer companies, with the opportunity to earn more or less relative to the market median based on actual corporate performance. (T 26 pp 241-42) He testified that EPS and total shareholder return metrics as part of incentive pay benefits customers. According to witness Silinski, to achieve strong incentive results, the Company must operate reliably and safely, deliver strong customer service, and control costs and grow the Company. EPS and TSR measures overall financial performance, and overall financial performance in turn can reflect how employees take action on a routine basis to support the efficient delivery of safe and reliable energy to customers. (T 26 p 245)

The Stipulation provides that Company 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.

Sponsorships and Donations

In her direct testimony, Public Staff witness Boswell adjusted O&M expenses to remove amounts 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. According to witness Boswell, these expenses should be disallowed because they do not represent actual costs of providing electric service to customers. (T 26 p 599)

In her rebuttal testimony, Company witness McManeus opposed part of the Public Staff's adjustment. (T 6 p 311) In 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

In her testimony, Public Staff witness Boswell explained that the Company made an adjustment to remove some lobbying expenses from the test year. She further adjusted O&M expenses to remove additional lobbying costs. In determining what costs should be removed, she applied the "but for" test for reporting lobbying costs as used in a Formal Advisory Opinion of the State Ethics Commission dated February 12, 2010. She explained that the Commission recognized at pages 70-71 of its 2012 Dominion North Carolina Power Order in Docket No. E-22, Sub 479, that lobbying included not only employees' direct contact with legislators, but also other activities preparing for or surrounding lobbying that would not have been conducted but for the lobbying itself. In applying this test, she removed O&M expenses associated with stakeholder engagement, state government affairs, and federal affairs that were recorded above the line. (T 26 pp 595-96)

In her rebuttal, Company witness McManeus explained why the Company opposed the adjustment. She explained that in 2016, the Company engaged a third-party consulting company to perform a detailed time study for the purpose of determining the percentage of time certain individuals spent on lobbying activities.

She stated that the Company booked its journal entries to ensure that the 2016 labor costs were aligned with the results of the study. (T 6 pp 327-28)

In the Stipulation, the Company accepted the Public Staff's recommended adjustment to lobbying.

Board of Directors Expense

In her direct testimony, Public Staff witness Boswell recommended an adjustment to remove 50 percent of the expenses associated with the BOD of Duke Energy Corporation that have been allocated to DEC. The expenses allocated to DEC encompass the BOD's compensation, insurance, and other miscellaneous expenses. According to witness Boswell, it is appropriate and reasonable for the shareholders of the larger electric utilities to bear a reasonable share of the costs of compensating those individuals who have a fiduciary duty to protect the interests of shareholders, which may differ from the interests of ratepayers. Further, Directors' and Officers' liability insurance, while a necessary expense for a corporation, has been utilized to defend the Board in suits brought by shareholders regarding issues such as coal ash. Witness Boswell stated it is appropriate for shareholders to share the cost of the insurance with ratepayers. (T 26 p 589)

In his rebuttal, Company witness Siliniski asserted that by definition, the Company is required to have a BOD and that therefore the costs are costs of service. (T 26 p 252)

In the Stipulation, the Company accepted the Public Staff's recommended adjustment to BOD expense.

Salaries and Wages Expense

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. (T 6 p 262) This adjustment was further updated in her supplemental filings.

Public Staff witness Boswell included an adjustment to the Company's updated payroll to include the updated payroll allocation factors in her direct testimony. (T 26 p 586) In her rebuttal, witness McManeus did not oppose the Public Staff's update. However, witness Boswell's adjustment was affected by the Public Staff's DEBS to DEC allocation, which the Company opposed. Therefore, witness McManeus revised the Public Staff's salaries and wages expense to fully incorporate the change related to labor charged by DEBS to DEC. (T 6 pp 320-21)

In her second supplemental testimony, filed after witness McManeus' rebuttal, Public Staff witness Boswell adjusted the Company's updated payroll to reflect annualized payroll through December 31, 2017. 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. (T 26 p 616)

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 Public Staff witness Boswell. The Stipulation did not include the specific amount of the adjustment. In an affidavit filed on April 10, 2018, witness Boswell presented the quantification of the salaries and wages expense agreed upon by the Public Staff and the Company.

State EDIT Refund

In this proceeding, the Company included an adjustment to amortize the State EDIT 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. Witness Boswell testified that the Public Staff believes that it would be beneficial to return the State EDIT to customers through a rider that will expire at the end of a two-year period. (T 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.

After careful consideration of all of the evidence in this proceeding, including the Stipulation, the Commission finds and concludes that the stipulated adjustment related to State EDIT, as discussed above, is just and reasonable to all parties. The Commission further concludes that that appropriate level of State EDIT to be refunded to customers is $42.577 million annually for the four years following the effective date of the rates approved in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-20

The evidence supporting these findings of fact and conclusions is contained in the verified Application and Form E-1 of the Company, 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 Rose, AGO witness Woolridge, CIGFUR 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. Attorney Gen. Roy Cooper, 366 N.C. 484, 739 S.E.2d 541, 546-47 (2013) (Cooper I).

In this case, the 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 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 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 the DEP's 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)[7];
- 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;

[7] 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.

- 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); and

- The 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. Utilities Commission v. General Telephone Co. of the Southeast, 281 N.C. 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. 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.
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> * * *
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> [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 DEP'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). 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. 366 N.C. 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. <u>State ex rel. Utils. Comm'n v. Pub. Staff,</u> 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.
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> 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.
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> Charles F. Phillips, Jr., The Regulation of Public Utilities, 3d ed. 1993, pp. 381-82. (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 we 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; Cooper IV, 367 N.C. at 650; Cooper III, 367 N.C. at 450), 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, quoting State ex rel. Utils. Comm'n v. Pub. Staff-North Carolina Utils. Comm'n, 323 NC 481, 490 (1988).

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; Cooper III, 367 N.C. at 451.

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 used the Constant Growth Discounted Cash Flow (DCF) model, the multi-stage DCF Gordon method, the multi-stage DCF Terminal Price/Earnings, 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 focused upon capital market conditions as they affect the Company's customers in North Carolina.

For his DCF calculation dividend yield, 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%.[8]

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.

[8] 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 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 produces a range of results from 8.70% to 9.31%.

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%.

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 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%.

Witness Hevert testified that the regional economic conditions in North Carolina were substantially similar to the United States, such that there is no direct effect of those conditions on the Company’s cost of equity.

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 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 over-all 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 result. 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 continue 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 cost of equity.

Witness Parcell explained his 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 Parcel applied the comparable earnings methodology by examining realized rate of returns 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 show 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, 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 a settlement, it was his view that the cost of capital components of the Stipulation are a reasonable resolution of 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 DEP'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 the comparable earnings analysis is based on the opportunity cost principal 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 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 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 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 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.[9]

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

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

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 to both his and Mr. Hervert's proxy groups of electric utilities. Dr. Woolridge's 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.

For Dr. 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 Mr. 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, his 5.5% value is a conservatively high estimate of the market risk premium. He also testified 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. Dr. Woolridge's CAPM equity cost rate was 7.9% for both his and Mr. 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 the 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 was 4.75% to 5.75%, and his calculated DCF range was 8.0% to 9.0%

CUCA witness O'Donnell in his CE analysis included 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 CE 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.

For his risk premium analysis, 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. They 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. He 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 Mr. Hevert's proxy group.

Mr. Strunk testified that Mr. 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 Mr. Hevert's proxy group. Mr. 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 and Light 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%. (T 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 Evidentiary 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 Statewide 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 was 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 Hearings and Further Conclusions

The Commission's review also includes consideration of the evidence presented during the public hearings by public witnesses, almost all of whom presently are customers of DEC. The hearings provided over 75 witnesses the opportunity to be heard regarding their respective positions on DEC's application to increase rates. The Commission held three evening hearings throughout DEC's North Carolina service territory to receive public testimony. The testimony presented at the hearings illustrates in detail the difficult economic conditions facing numerous North Carolina citizens. The Commission accepts as credible, probative, and entitled to substantial weight the testimony of the public witnesses.

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

As noted above, the Commission's duty under G.S. 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 G.S. 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 G.S. 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 G.S.62-133(b)(3). The Commission must approve depreciation rates pursuant to G.S.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 Commission Order affect not only the ability of DEC's consumers 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 G.S. 62-133, rates in North Carolina are set based on a modified historic test period.[10] A component of cost of service as important as return on investment is test year revenues.[11] 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

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[10] G.S. 62-133(c).

[11] G.S. 62-133(b)(3).

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 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 the increase in DEC's rates will 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 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 increased 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 witness Phillips. The Commission finds that the CE analysis testimony of Public Staff witness Parcell, the risk premium analysis testimony of DEC witness Hevert, the CE 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 earning 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 principal 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 ten basis points below witness Hevert's risk premium's implied rate of return on equity range of 10.0% to 10.32%.

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.

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 rate of return on equity of 9.1%. The Commission determines that all of these DCF analyses in the current market produce unrealistic 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 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 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% common equity and 47% long-term debt. (T 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.

DEC 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." (Id.) At the end of the December 31, 2016 test year, the DEC actual regulatory capital structure[12] was 52.8% equity and 47.2% debt (Id. at 43), and the 13-month average equity ratio was 54.5%. (T 4 p72) He testified that through November 2017, DEC has maintained a 13-month average equity ratio of 53.3%, per the Form ES-1 approach. (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 witness Parcell, for the Public Staff, and witness De May, for the Company, supported the agreed upon 52/48 ratio. Parcell testified that the 52/48 ratio reflects a reasonable compromise, and also incorporates a reduction from the Company's currently authorized 53/47 ratio. (T 26 p 894) Mr. De May testified that the "stipulated capital structure is reasonable when viewed in the context of the overall Stipulation," and it would be viewed by the ratings agencies as positive and constructive. (T 4 p 88) Witness Hevert's

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

settlement testimony also supported the stipulated 52/48 capital structure. (T 4 p 412)

Witness De May presented, in his rebuttal testimony, the capital structures of four large regulated operating electric utilities located in the southeastern United States as of December 31, 2013-16 and the operating third quarter of 2017. Florida Power and Light's capital structure is an outlier for which the Commission gives no weight. The 4.75 year averages for the remaining three are Virginia Electric & Power, 52.9% equity, SCE&G, 51.4% equity, and Georgia Power, 50.8% equity. The average of the three is 51.7% equity. (T 4 pp 63-64)

DEC witness Hevert testified in his rebuttal testimony he focused on the capital structures of vertically integrated electric utilities but excluded jurisdictions such as Michigan and Arkansas that, unlike North Carolina, include non-investor supplied sources of capital in the ratemaking capital structure. He also excluded Indiana, which calculates rate base on a fair value basis and makes a corresponding adjustment to the capital structure. Mr. Hevert testified excluding those cases produces an average equity ratio of 50.51% approved by Commissions for vertically integrated electric utilities. (T 4 p 390)

CUCA witness O'Donnell and AGO witness Woolridge recommended that the Commission reject DEC's capital structure proposal and instead advocated a 50/50 hypothetical structure. Tech Customers witness Strunk testified that DEC's proposed equity ratio of 53% is on the high end of equity ratios approved by state commissions in the last three years, indicating low financial risk for DEC compared to the electric operating subsidiaries of the companies in Mr. Hevert's proxy group.

Witness O'Donnell compiled the 2016 equity ratios of the Hevert proxy group adding only Avista. The average equity ratio of these 17 companies which Mr. O'Donnell named as his comparable group was 48%. (T 18 pp 97-98) He also testified that based upon data from SNL, the average common equity ratio granted to electric utilities by regulators in 2017 was 49.1%. He testified that the 2016 Duke Energy Corporation equity ratio was 47.4%. He concluded that the equity ratio requested by DEC in this case is excessive compared to the comparable group at 48%, Duke Energy Corporation at 47.4%, and the average common equity ratio of 49.1% as approved by state regulators across the United States.

AGO witness Woolridge testified that as shown on Panel B of his Exhibit JRW-4, the median common equity ratios of his 28 electric company proxy group and Mr. Hevert's 19 electric company proxy group are 46.8% and 44.6%, respectively. He testified that DEC's proposed capital structure of 53% common equity is significantly higher than the two proxy groups and DEC's parent, Duke Energy Corporation. (T 11 p 111) Dr. Woolridge recommended a capital structure with 50.0% common equity, which was above the averages of the two proxy groups and Duke Energy Corporation. (T 4 p 116)

Witnesses O'Donnell and Woolridge provided analyses to support their 50/50 capital structure recommendations. The principal rationale for witnesses O'Donnell's and Woolridge's 50/50 recommendation is their comparisons of capital structures of publicly-traded holding companies, not operating electric utility companies. This Commission has previously commented on and rejected the use of parent company structures as opposed to operating company 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 (December 7, 2009) (2009 DEC Rate Order), at 27-28. Parent and operating companies 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."

Witness Hevert testified 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. (T 4 pp 287-88) Here all three criteria are met. DEC does issue its own debt and is rated separately from its parent company, and the evidence presented by witnesses De May and Hevert shows that its capital structure is generally consistent with that of other electric operating companies, especially vertically-integrated companies. (Id. at 63-64 (De May); Id. at 412 (Hevert).)

AGO witness Woolridge further testified that just as there is a direct correlation between the utility's authorized return on equity and the utility's revenue requirements (the higher the return, the greater the revenue requirement), there is a direct correlation between the amount of equity in the capital structure and the revenue requirements the customers are called on to bear. He testified that equity capital is more expensive than debt. Not only does equity command a higher cost rate, it also adds more to the income tax burden that ratepayers are required to pay through rates. As the equity ratio increases, the utility's revenue requirements increase and the rates paid by customers increase. If the proportion of equity is too high, rates will be higher than they need to be. He testified that for this reason, the utility's management should pursue a capital acquisition strategy that results in the proper balance in the capital structure.

In addition to the Commission's analysis of the witnesses' 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 required 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 concessions the Company made to reduce its revenue requirement and alleviate the impact of the proposed rate increase 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 rate of return on equity, the Commission recognizes the financial difficulty that the increase in DEC's rates will 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.

Cost of Debt

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

In their pre-filed direct testimony, Company witnesses McManeus and De May testified that the Company's revenue requirement was determined using an embedded cost of long-term debt of 4.74%.

Public Staff witness Parcell, in his direct testimony, supported the embedded cost of debt on November 30, 2017 of 4.57% and later, in his supplemental testimony, supported the December 31, 2017 cost of long-term debt of 4.59% in the Stipulation. He testified the long-term debt cost of 4.59%, in the Stipulation, reflected the impact of a new long-term debt issue in November 2017. The Stipulation's 4.59% debt cost gives customers the benefit of reductions in DEC's lower cost of debt after the end of the test year.

No intervenor offered any evidence supporting a debt cost below 4.59%. 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 FINDINGS OF FACT NOS. 21-24

The evidence supporting these findings of fact and conclusions can be found in the testimony of Company witnesses Fountain, McManeus, McGee and Kerin, the testimony of Public Staff witness Lucas, and the Stipulation.

In his direct testimony, DEC witness Fountain stated that although costs related to beneficial reuse are included in DEC's base rate case, the Company believes that certain amounts are more appropriately recovered through the fuel clause. (T 6 p 169 n 1)

Witness McManeus testified that of the $524.0 million expected deferred balance, $85.9 million, which is $73.1 million of spend and $12.8 million of return, is related to 2017 beneficial reuse projected costs. As noted by witness Fountain, witness McManeus stated that these amounts are included in the Company's request, but DEC believes that these costs are more appropriately recovered through the annual fuel rider. Witness McManeus explained that if the Commission approves the fuel rider treatment requested by the Company, DEC will remove $85.9 million from the deferred balance in this adjustment. (T 6 p 260)

In her direct testimony, Company witness McGee testified that the beneficial reuse of CCR constitutes a sale of a by-product produced in the generation process, and, therefore, associated gains or losses on the sale should be included in the fuel adjustment clause under G.S. 62-133.2 (a1)(9). According to witness McGee, a sale has occurred when the title to a by-product is transferred to a third party, and the by-product, having value to the third party, will be beneficially reused. In this particular case, the amounts for which the Company is requesting recovery represent a net loss on the sale of CCR that is to be used as structural fill, which is a beneficial reuse. She testified that the particular transaction, as further discussed in witness Kerin's testimony, involves the sale of CCR produced at DEC's Riverbend coal plant, and therefore the input to the by-product is the coal that has been burned at Riverbend to produce generation. Thus, she contended that such coal burned has been and continues to be a "fuel or fuel-related cost" under the fuel clause statute as described above. Witness McGee testified that a sale of a by-product is different than disposal of a by-product in that the disposal of a by-product may involve some movement of the by-product and/or transfer of title, but there is no reuse or alternative use of the by-product. According to witness McGee, for transactions that the Company considers to be a sale, the by-product's intrinsic value is recognized in the reuse of the by-product. Finally, witness McGee cited certain statements of the Commission in a 2016 Commission Report to the North Carolina General Assembly[13] (Commission Report) regarding incremental cost incentives related to CCRs, filed in Docket No. E-100, Sub 146, as supportive

[13] Report of the North Carolina Utilities Commission to the Joint Legislative Commission on Governmental Operations, the Joint Legislative Transportation Oversight Committee, and the Environmental Review Commission Regarding The Incremental Cost Incentives Related To Coal Combustion Residuals Surface Impoundments For Investor-Owned Public Utilities In North Carolina, January 15, 2016.

of the Company's position that beneficial reuse constitutes a sale under the fuel adjustment clause. (T 26 pp 195-96)

Company witness Kerin testified that DEC is now selling excavated ash for reuse in the Brickhaven mine reclamation project, a large scale, fully-lined, beneficial reuse project in Moncure, North Carolina. He testified that he agreed with Company witnesses Fountain and McGee that the certain beneficial reuse costs are more appropriately recovered through fuel clause proceedings. According to witness Kerin, coal has been used as the fuel to produce power at DEC's Riverbend plant. A by-product of that process is coal ash. As a means to handle that by-product, ash is sold to the Brickhaven mine to be used as structural fill, which is a beneficial reuse. (T 14 pp 112-13)

Public Staff witness Lucas testified that the costs relating to the disposal of coal ash at Brickhaven, to the extent they are reasonable and prudent, should be recovered in base rates and not through the fuel adjustment clause because the costs did not result from the sale of coal ash. Witness Lucas provided background regarding the Charah transaction at issue. He testified that Brickhaven is a former clay mine consisting of 334 acres located in Chatham County, North Carolina. By Special Warranty Deed recorded on November 13, 2014, Green Meadow, LLC, a wholly owned subsidiary of Charah, purchased Brickhaven from General Shale Brick, Inc. On June 5, 2015, Green Meadow, LLC, and Charah received a permit from DEQ to construct and operate Brickhaven as a "Solid Waste Management Facility, Structural Fill, Mine Reclamation". Charah is a Kentucky-based company, and according to its website, it "is the largest privately-held provider of coal combustion product (CCP) management for the coal-fired power generation industry in the U.S."[14] (T 26 pp 758-59)

Witness Lucas explained that in July of 2014, DEBS, on behalf of DEC and DEP, issued a bidding event for the excavation, transportation, and off-site storage of the full volume of ash at four sites: Riverbend, Dan River, and Sutton in North Carolina and W.S. Lee in South Carolina. In August of 2014, DEBS requested pricing from a short list of bidders to install the infrastructure to remove, transport, and place off-site the Riverbend Plant ash stack (Riverbend Phase 1 request). Charah was awarded the contract. (T pp 759-60)

Witness Lucas described the contractual arrangement between DEBS and Charah regarding the removal of coal ash from the Riverbend Plant. He stated that DEBS, as agent for DEC and DEP, and Charah entered into Master Contract 8323 (Master Contract) dated November 12, 2014, for the Phase 1 Excavation Work at the Riverbend and Sutton Plants.[15] Charah is referred to as the "Seller" or "Contractor" in the Master Contract. Charah is not referred to as a "Buyer". The

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[14] http://charah.com.

[15] The Master Contract was entered into the record in the DEP Rate Case as McGee Confidential Public Staff Cross-Examination Exhibit No. 6. The deed for Brickhaven was recorded the day after the Master Contract was executed. The timing of these two events (along with the fact that the Master Contract identifies Brickhaven as the site for placement of the Riverbend and Sutton ash) tends to show that Brickhaven was purchased for the purpose of providing a disposal site for DEC's (and DEP's) coal ash.

Master Contract defined the type and scope of work, terms and conditions, pricing, and invoicing. The Master Contract contemplated the issuance of subsequent Purchase Orders as written authorization to proceed with the scope of work identified in the Purchase Order. (T 26 p 760)

The Riverbend Phase 1 Work Scope was set forth in Exhibit D-1 of the Master Contract. It included the installation of haul roads, engineering the development of a rail loading system, erosion and sedimentation control, dewatering, ash pond excavation, transportation, unloading, and placement. The Seller's (i.e., Charah's) Pricing Schedule for Riverbend was set forth as Exhibit E. The Pricing Schedule included both fixed pricing and per ton pricing. The fixed pricing was for mobilization, site preparation, erosion, and sedimentation control work. The per ton pricing was for excavation, loading and transportation, unloading, development, placement, home and field office overhead, and profit. DEBS and Charah entered into Purchase Orders authorizing Charah to transport ash from Riverbend by truck to Brickhaven and then to construct and transport ash by rail to Brickhaven. Purchase Orders 2278895 and 5050808 constituted the vast majority of the excavation, transportation, and disposal work for Riverbend; change orders were executed for these Purchase Orders. (T 26 pp 761-62)

Witness Lucas testified that nothing in the bid documents, contracts, purchase orders, or change orders for the Riverbend Plant assign any value to the CCR to "net" against the cost of the services provided by Charah. When asked to provide all documents that show how the Company or Charah calculated the "net value" or discount value of coal ash when setting the cost of services provided by Charah, the Company responded that it had no responsive documents. In addition, when asked how much Charah paid the Company for the Riverbend coal ash, the Company responded that "there is not a defined monetary price in the operative documents for the Riverbend ash but rather Charah compensated the Company for the ash through the provision of certain services at Riverbend." (T 26 p 764)

Witness Lucas testified that DEC and Charah knew how to assign a value to CCR in a sale, as demonstrated by the Master By Product Marketing, Sales, and Storage Agreement (Agreement) entered into by DEC, DEP, and Charah in December of 2013, and associated Work Orders, which obligated Charah to purchase coal ash from DEP or DEC, as applicable, at a price as set forth in the Work Orders. This Agreement formed the basis for the sale of coal ash at the Belews Creek and Marshall plants via Work Orders entered into by DEC and Charah on January 1, 2014. (T 26 p 764)

Witness Lucas asserted that the specific provisions relating to the services and pricing in the Master Contract, Purchase Orders, and change orders for Riverbend all support the conclusion that the arrangement was one for Charah to provide ash disposal services to DEC, not for a sale of DEC's CCR to Charah. In its data responses, DEC referenced Sections 3 and 4 of the Master Contracts in support of its assertion that a sale occurred. The Company produced several master contracts[16] for ash excavation and landfill disposal with the same or similar provisions. Witness Lucas asserted that this language is boilerplate and does not support a finding that a sale has occurred. No one would purchase coal ash just to put it in a landfill. (T 26 p 765)

Further, witness Lucas testified, the language of Section 3 itself, relating to Title, does not support a conclusion that the contract is one for a sale of coal ash. The second sentence of that section states that "the Contractor [Charah] is not assuming any responsibility for any liabilities arising out of or are related to the creations, existence, storage, or handling of the Ash prior to the time title to the Ash passes to Contractor." In the Public Staff's opinion, this language supports a conclusion that the parties considered the ash to have no value and in fact was a liability, and the responsibility for its transport and ultimate disposition needed to be contractually determined. (T 26 p 765)

Witness Lucas testified that regarding Section 4, although the provisions state that the services to be performed by Charah constituted payment by Charah for the ash, as noted above, DEC has admitted that there was no defined price for the ash and no documentation showing that the parties assigned any value at all to the ash. Witness Lucas asserted that there was no defined price because the ash had no value. The provisions of both the Master Contract and Purchase

[16] These contracts were admitted into evidence in the DEP Rate Case as Public Staff McGee Confidential Exhibits 7, 8, 9, and 10.

Orders, along with the circumstances surrounding them, overwhelmingly point to a contract for services, not a sale. (T 26 p 766)

Witness Lucas also addressed the findings in the Commission Report cited by Company witness McGee as support for DEC's position. He testified that the findings in the Commission Report do not support DEC's conclusion that the costs of the beneficial reuse of coal ash are recoverable through the fuel clause. The General Assembly in the legislation directed the Commission to specifically address in its report "possible revisions to the current policy on allowed incremental cost recoupment that would promote reprocessing and other technologies that allow the reuse of CCRs stored in surface impoundments for concrete and other beneficial end uses". The Commission's Report examined the statutory framework for cost recovery and concluded that current policies and practices are adequate to encourage reuse of CCRs for concrete and other beneficial end uses. However, as recognized by the Commission in the Report, recovery through the fuel clause presupposes that there is a sale. On page 13 of the Report, the Commission stated, "Customers' rates are adjusted annually to include profits or losses associated with efforts to sell CCRs for beneficial reuse." On page 14 of the Report, the Commission recognized that "sales of CCRs typically result in immediate net costs to ratepayers." The Commission did not conclude in its Report that the costs of processing CCRs for beneficial use, without a sale, are recoverable in the fuel clause and did not recognize the re-use of coal ash from surface impoundments as a common practice. (T 26 pp 766-67)

Witness Lucas stated that if there is an actual sale of CCRs, cost recovery through the fuel clause may be appropriate, if the costs are reasonably and prudently incurred. Where, however, there is a contract for services not involving a sale of coal ash, costs arising from that contract should not be recoverable through the fuel clause. Witness Lucas concluded that the true purpose of moving CCRs from Riverbend to Brickhaven is environmental remediation and the disposal of CCRs, and not the sale of a byproduct. (T 26 p 767)

In her rebuttal, Company witness McGee disagreed with witness Lucas' characterization of the contractual arrangement with Charah involving the movement of ash from the Riverbend Plant to Brickhaven. She asserted that DEC was compensated for the value of the coal ash. She explained that under the arrangement, the compensation to DEC was expressed indirectly through the values agreed to on other terms and conditions in the contract. In other words, the cost of services provided by Charah would have been higher without the sale of the coal ash from the Company to Charah. She further asserted that the coal ash had value to Charah in that it was used in a process as a substitute for an alternative material. Without the purchase of the coal ash, Charah would have needed to procure topsoil or another material to use as structural fill, an added cost that Charah was able to avoid. She concluded that the overall economics of the sales agreement therefore reflected the intrinsic value of the CCRs. (T 26 p 202)

Witness McGee identified two provisions of the Master Contract in support of her position. First, per Section 3 of Exhibit B to the Master Contract (Exhibit B), the Company transferred title to, risk of loss of, and responsibility for the coal ash to Charah once the coal ash is loaded in to truck or railcar at Riverbend for transportation to Brickhaven. According to witness McGee, this provision indicates that the coal ash had value to the parties that had to be transferred through title. Further, the fact that Charah agreed to accept the transfer of title and risk of loss at the point that the coal ash was loaded onto its trucks or rail cars for delivery is strong evidence that the coal ash had transferable value. (T 26 p 203)

Witness McGee also cited Section 4.2 of Exhibit B in support of the Company's position, which provides in pertinent part that, "payment of the Service Fee by Duke Energy to Contractor . . . together with any Ash that is transferred by Duke Energy, to Contractor under the applicable Purchase Order, constitutes payment in full, by Duke Energy to Contractor for any and all of contractor's costs to perform the Services...." Witness McGee asserted that this section clearly acknowledges that the coal ash serves as partial consideration for the services rendered by Charah. She stated that it was therefore understood and accepted by both parties that the service fee charged by Charah for its services was offset by the value of the coal ash to Charah, thereby constituting a sale. (T 26 p 203)

Witness McGee also took issue with witness Lucas' characterization of the arrangement as a "disposal". She stated that the coal ash at Riverbend was not thrown away or placed in a landfill, but replaced the topsoil that would have been used as structural fill in the reclamation of the Brickhaven mine. Further, she noted that the EPA definition of beneficial reuse is "the reusing of a material in a manner that makes it a valuable commodity, such as use in a manufacturing process or as a structural fill." Based on the EPA definition, witness McGee maintained that the use of the Riverbend coal ash as structural fill for the Brickhaven mine indicates that the coal ash was a valuable commodity. (T 26 p 204)

Witness McGee also cited Section 2.1 of Exhibit B, which states, "[t]he Parties desire that Contractor excavate certain quantities of Ash from the Ash Ponds or Onsite Storage, transport such Ash off the Station property for resale to Contractor for *beneficial reuse* in the production of construction products, as an engineered structural fill and/or for closure of a mine reclamation projects, etc. . . ." (emphasis added). She asserted that both parties clearly contemplated and agreed upon the use of the CCRs, which is expressed in the contract. Accordingly, the purpose of this transaction was the sale of CCRs produced at the Company's Riverbend coal plant to Charah for beneficial reuse at Brickhaven. (T 26 p 204)

Witness McGee testified that the Company has included the gain/loss on the sale of coal ash in the fuel adjustment clause in the past. Specifically, she noted that the losses on the sale of coal ash from the Asheville plant to the Asheville Airport as structural fill have been included in the fuel adjustment clause since 2008. She noted that the Master Contract had the same language as that used for the coal ash from the Asheville Plant. (T 26 p 205)

Witness McGee also took issue with witness Lucas' assertion that Section 3 of the Master Contract does not support a conclusion that the contract is one for the sale of coal ash. She stated that this language supports a conclusion that the parties considered the ash to be an asset that has value, for which transfer of title needed to be determined in the contract. Further, according to witness McGee, the language in Section 3 makes it clear the Company and Charah are treating the coal ash as an asset and are agreeing that Charah will take the asset free and clear of all liabilities arising out of or related to the coal ash prior to the sale. Witness McGee contended that this position is supported by the language in some of the waste management services contracts referenced by witness Lucas. According to Ms. McGee, the language in the waste management services contracts indicated that the parties considered the ash being sent to a landfill as a liability for which the Company agreed to maintain responsibility even after disposal, which supports the Company's position that the transfer of title from the Company to Charah in the Master Contract indicates that the Company was conveying (and Charah was receiving) an asset. (T 26 pp 206-07)

Finally, witness McGee concluded that generally a master contract provides the commercial framework on how the parties will conduct business. Whether certain provisions in the Master Contract apply to a particular transaction depends on how the coal ash is being treated. (T 26 p 208)

In the Stipulation, the Company and the Public Staff agreed that given the Commission's Findings of Fact Nos. 57-59 and associated conclusions in the DEP

Rate Order, the Company would withdraw its request to recover 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 effect of this is that the Stipulating Parties agreed that the recovery of these costs is left in the Company's deferred CCR balance for consideration of recovery in the Company's base rates.

<u>Discussion and Conclusion</u>

In its Application, DEC seeks to recover certain CCR costs 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, through the fuel adjustment clause on the grounds that the beneficial reuse of CCRs constitutes a sale of a by-product produced in the generation process. The fuel adjustment statute, G.S. 62-133.2, allows electric public utilities to recover through an annual rider certain fuel and fuel-related costs. G.S. 62-133.2(a1)(9) provides:

> Cost of fuel and fuel-related costs shall be adjusted for any net gains or losses resulting from any sales by the electric public utility of by-products produced in the generation process to the extent the costs of the inputs leading to that by-product are costs of fuel or fuel-related costs.

It is undisputed that CCRs are a by-product produced in the generation process. The issue is whether the transaction between DEC and Charah as reflected in the Master Contract represents a sale of a by-product.

As was discussed in the Stipulation, the Commission addressed this issue in the DEP Rate Order. The contract at issue in the DEP Rate Order is the same Master Contract at issue in this case. The DEP Rate Order made certain findings and conclusions regarding the Master Contract and whether costs associated with beneficial reuse, without a sale, are recoverable through the fuel adjustment clause.

First, the findings of the Commission Report cited by witness McGee do not support a finding that the costs associated with beneficial reuse, without a sale, are recoverable through the fuel adjustment clause. The General Assembly directed the Commission to specifically address in its Report "possible revisions to the current policy on allowed incremental cost recoupment that would promote reprocessing and other technologies that allow the reuse of coal combustion residuals stored in surface impoundments for concrete and other beneficial end uses." The Commission Report examined the statutory framework for cost recovery and concluded that current policies and practices are adequate to encourage reuse of CCRs for concrete and other beneficial end uses. However, as noted by Public Staff witness Lucas and as recognized by the Commission in the Report, recovery through the fuel clause presupposes that there is a sale. On page 13 of the Report, the Commission stated, "Customers' rates are adjusted annually to include profits or losses associated with efforts to sell CCRs for beneficial re-use." On page 14 of the Report, the Commission recognized that "sales of CCRs typically result in immediate net costs to ratepayers." The

Commission did not conclude in its report that the costs of processing CCRs for beneficial use, without a sale, are recoverable in the fuel clause.

In addition, the record in this case, just as in the DEP Rate Case, does not support a finding that the costs associated with the Master Contract resulted from a "sale" of CCRs. The Company admitted both in data responses and during the expert witness hearing that nothing in the Master Contract or its associated documents included pricing or discounts to account for a sale of the CCRs. Further, nothing in the bid documents, contracts, purchase orders, or change orders relating to the Master Contract assign any value to the CCRs to "net" against the cost of the services provided by Charah. Moreover, the evidence shows that DEC and Charah knew how to assign a value to CCRs in a true sale. Public Staff witness Lucas testified, and the Company did not challenge, that pursuant to a Master By Product Marketing, Sales, and Storage Agreement (Agreement) entered into by DEC, DEP, and Charah in December of 2013, and associated Work Orders, Charah was obligated to purchase CCRs from DEP or DEC, as applicable, at a price as set forth in the Work Orders. This Agreement formed the basis for the sale of CCRs at the Belews Creek and Marshall plants via Work Orders entered into by DEC and Charah on January 1, 2014.

The Company relies on the existence of three provisions in Exhibit B of the Master Contract in support of its contention that a sale of CCRs occurred. Company witness McGee states in her testimony that per Section 3 of the Master Contract, the Company transferred title to, risk of loss of, and responsibility for the

CCRs to Charah once the CCRs are loaded in to truck or railcar at Riverbend, indicating the CCRs had value. This interpretation – that transfer of title relates to the transfer of liability - is supported by the language in the second sentence of Section 3, which states that the Contractor is not assuming any responsibility for any liabilities arising out of or relating to the creations, existence, storage, or handling of the ash prior to the time title to the ash passes to Contractor. The Commission finds and concludes that Section 3 of the Master Contract does not support a finding that the Riverbend CCRs had value. On the contrary, the balance of this evidence supports the conclusion that possession of the CCRs represented a liability, not an asset.

The Company also cites Sections 4.1 and 4.2 of Exhibit B of the Master Contract, which in essence state that the services performed by Charah constitute payment for the CCRs. The Commission is not persuaded that inclusion of these provisions demonstrate that a sale of CCRs occurred. These provisions are part of the Duke Energy Standard Terms and Conditions for Ash Reclamation and Placement that have been included in other contracts for CCR services, regardless of the type of service and disposal method. The master contract for the Phase 1 Excavation Work at Dan River and W. S. Lee, discussed by witness McGee in her rebuttal, contain the same provisions and pricing schedules similar to the Master Contract, and witness McGee admitted that the costs incurred under that contract should not be recoverable under the fuel clause, because the CCRs were landfilled, not placed in a structural fill. The Commission finds that these provisions are boilerplate that do not support the conclusion that a sale of the Riverbend CCRs occurred.

Based on a preponderance of the evidence, including the Stipulation, the Commission finds and concludes that the specific provisions relating to the services and pricing in the Master Contract, Purchase Orders, and change orders for Riverbend, the circumstances surrounding the transaction, and the Stipulation, all support the conclusion that the arrangement was one for Charah to provide CCR excavation, transportation, and disposal services to DEC, not for a sale of DEC's CCRs to Charah under G.S. 62-133.2(a1)(9).

As noted at the beginning of this discussion, DEC witness McManeus testified that of the $524.0 million expected deferred balance, $85.9 million, which is $73.1 million of spend and $12.8 million of return, is related to 2017 beneficial reuse projected costs. Witness McManeus explained that if the Commission approves the fuel rider treatment requested by the Company, DEC will remove $85.9 million from the deferred balance in this adjustment. The Commission having denied the recovery of the $85.9 million Charah costs in fuel rates, the recovery of this $85.9 million is left in DEC's $524.0 million deferred CCR balance for consideration of recovery in DEC's base rates.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence supporting this finding of fact and conclusions is contained in the Stipulation, the verified Application and Form E-1 of DEC, the testimony and exhibits of Company witness McGee and Public Staff witness Boswell, and the entire record in this proceeding.

In her direct testimony, Company witness McGee provides support for the fuel component of proposed base rates for all customer classes and the annualized fuel expense for DEC's test period. Witness McGee testified that the Company proposes to use the following base fuel factors by customer class (excluding gross receipts tax and regulatory fees):

•	Residential	1.9131 cents per kWh
•	General Service	2.0570 cents per kWh
•	Industrial	2.1492 cents per kWh

She explained that these proposed factors are equal to the total prospective fuel and fuel-related cost factors proposed on March 8, 2017 in Docket No. E-7, Sub 1129. These factors represent the fuel-related amounts that DEC is proposing to collect from its North Carolina retail customers starting September 1, 2017. Witness McGee stated that DEC's intent in using the fuel-related factors that were proposed at the time that 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. (T 26 pp 192-94)

As shown on McGee Exhibit 1, the Company's North Carolina retail adjusted fuel and fuel-related costs expense for the test period was $1,157,548,563. According to witness McGee, this amount was calculated using the base fuel cost factors identified above and North Carolina retail test period actual sales by customer class as adjusted for weather and customer growth. She testified that these amounts were used in the Company's pro forma adjustment calculations and are incorporated in the operating expenses shown on McManeus Exhibit 1. (T 26 p 193)

Public Staff witness Boswell incorporated the fuel factor approved by the Commission in DEC's last fuel case in Docket No. E-2, Sub 1129 to calculate the fuel expenses and revenues. She testified that the Company utilized the fuel factor it originally filed in the same docket, not the Commission-approved factor. The net effect of the adjustment is zero, as the adjustment to expenses is offset by the change to revenues.

Witness Boswell testified that the fuel revenue presented in the present rates column as filed by the Company should reflect fuel under present Commission-approved rates. She asserted that it is inappropriate to state fuel revenues at present rates at a level other than what the Commission has already approved. She stated that the Company's rationale for the fuel factors used by the Company was that the approved factors are lower than what the Company expects will be proposed in its next fuel proceeding. Witness Boswell testified that if DEC wanted a base fuel factor higher than the most recently Commission-approved factor, the Company should have presented the cost support to fully justify the change in fuel expense and the resulting proposed fuel factor, and increase fuel expense, not fuel revenue under present rates, to justify the increase. The increased fuel expense would have then been used to propose an increase in the base fuel factor as part of the overall rate change. (T 26 pp 584-85)

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 follows (amounts are cents per kWh excluding, regulatory fee): 1.7828 for residential customers; 1.9163 for general service and lighting customers; and 2.0207 for industrial customers.

No intervenor contested this provision of the Stipulation. Accordingly, the Commission finds and concludes that 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. 26

The evidence supporting this finding of fact and conclusion is contained in the Stipulation, the 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. This is the level of coal inventory that was utilized in DEC's last general rate case for the materials and supplies component of cash working capital, and was stipulated by the Public Staff and the

Company in the settlement agreement approved by the Commission in that case. (T 6 p 258; T 23 p 18)

In his pre-filed testimony, Public Staff witness Metz recommended adjustment to the materials and supplies component of cash working capital to reflect a 40-day coal inventory based on a 70% full load burn. (T 23 p 25) He testified that a 70% capacity factor recognizes that during a portion of the year, coal generation assets are operating substantially above his calculated weighted annual capacity factor of 39.7%. (T 23 p 25) Witness Metz based his recommendation of 40 days on the fact that the Company's coal generation, in terms of $/MWh, operates closer to the dispatch margin with its combined cycle natural gas generation than is typically the case with DEP's coal generation. In other words, lower delivered fuel prices for DEC's coal generation, combined with more efficient generation technology, places certain DEC coal generation assets closer to the dispatch stack "bubble" than DEP's coal generation assets. (T 23 p 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. Instead, 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 a targeted 40-day, 100% full load burn. (T 26 p 228)

Witness Miller testified that witness Metz's recommendation of 40-day coal inventory based on a 70% full load burn does not account for how delivery and supply risks and volatility in coal generation demand can negatively impact a reliable cost-effective coal supply. (T 26 pp 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. (T 26 p 231) 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. As such, having unreliable coal inventory levels could result in unfavorable impacts on customers. (T 26 p 229)

In the Stipulation, the Public Staff and DEC agreed that the Company shall reduce the amount of coal inventory included in working capital. Further, the Parties agreed that an increment rider should be approved to manage the transition, 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. For this purpose, three consecutive months of total coal inventory of 37 days or below will constitute a sustained basis. The Company reserves the right to request an extension of the May 31, 2020, date. The Stipulation further provides that the Company will adjust this rider annually, concurrently 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 trued up in that annual rider filing. For purposes of the coal inventory rider, the Stipulating Parties agreed that 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. In addition, the Company will conduct an analysis in consultation with the Public Staff demonstrating the appropriate coal inventory level given market and generation changes since the Company's rate case in Docket No. E-7, Sub 1026. The analysis shall be completed by March 31, 2019. No intervenor took issue 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 FINDINGS OF FACT NOS. 27-28

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, DEC's verified Application and Form E-1, the testimony of DEC witnesses Fountain and Simpson, and the testimony of Public Staff witness Williamson.

Company witness Fountain testified that a key area of focus for the Company is customer satisfaction, which the Company measures via a proprietary relationship study. Duke Energy NC Residential satisfaction scores are up over 10 points on average from 2013, with recent trends even higher. The most recent results of the industry's key benchmarking study – the 2017 J.D. Power Electric Utility Customer Satisfaction Study – published in July 2017, found DEC recognized as among the most improved in this year's study, up 52 points vs. 2016, or an increase of 5.2%. The utility industry, by comparison, was only up 39 points or 3.9%. Over the past year, DEC has cut the gap to top quartile for customer satisfaction to a mere 11 points, finishing in the 2nd quartile among large utilities nationally. Strong performance in 'PQ&R', 'Billing & Payment' and 'Customer Service' were the main drivers of DEC's improved showing. (T 6 pp 186-87)

Witness Fountain also testified that the Company conducts a transaction study to measure satisfaction with how the Company responds to customer service requests. As part of this study, a third-party research supplier conducts interviews with customers. The analysis of these interviews and surveys are used by the Company to implement improvements. Witness Fountain testified that through mid-2017, roughly 85 percent of DEC residential customers expressed high levels of satisfaction with key service interactions. (T 6 p 187)

Company witness Simpson described metrics the Company uses to measure the effectiveness of its transmission and distribution operations. He provided an overview of the transmission and distribution metrics used to measure the Company's reliability and reduce customer outages. The Company uses the System Average Interruption Duration Index (SAIDI), which indicates how often the average customer has a sustained outage, and the System Average Interruption Frequency Index (SAIFI), which indicates the total duration of an outage for the average customer. Witness Simpson stated that over the past eight years, both SAIFI and SAIDI show an unfavorable trend; this is mainly due to an uptick in vegetation management-related outages, weather, aging, assets, and distributed energy resources. (T 16 pp 97-101) On cross-examination, witness Simpson acknowledged that the SAIDI and SAIFI numbers improved from 2003 to 2012 and that the SAIDI and SAIFI numbers in 2003 were worse than they were in were in 2016. (T 16 pp 176-77; T 23 p 248) He also acknowledged that according to a data response provided by the Company, vegetation management is the single biggest contributor to the worsening trends in reliability, representing almost 21 percent of outages in the test year; weather only accounted for 1.82 percent. (T 23 pp 250-53; T 24 exhibits pp 113-15)

Public Staff witness Williamson agreed that the Company's SAID and SAIFI indices are worsening. Based on the trends, the Company's outages are increasing in frequency, and when they do occur they tend to have a longer duration on average. (T 22 p 47) He also testified regarding the types of complaints and inquiries received by the Public Staff's Consumer Services Division for the period January 2016 through December 2017. For that period, Consumer Services received approximately 9,600 direct contacts with DEC customers. The two highest frequency complaint categories were (1) payment arrangements 3,480 and (2) revising existing agreements on payment arrangements 2,520, representing 62% of all contacts with DEC customers. Less than 1% of the total contacts were related to service quality issues. He concluded that the quality of services provided by DEC to its North Carolina retail customers is adequate. (T 22 p 48)

The Company and the Public Staff agreed in the Stipulation that the overall quality of electric service provided by DEC is adequate.

The Commission finds and concludes that the Company's service quality is currently adequate. The Commission gives substantial weight to the testimony of Company witnesses Fountain and Simpson that the Company has performed satisfactorily in areas of customer satisfaction and reliability during the test period. The Commission reminds the Company that it is expected to promptly follow up and resolve any service-related customer complaints raised at the public hearings. The Commission also gives substantial weight to the testimony of Public Staff witness Williamson that based on DEC's statistics on outages and restoration times and on customer complaints, he concluded that DEC's quality of service is adequate.

While worsening from 2008 to 2016, DEC's SAIDI and SAIFI metrics for 2016 are slightly better than the 2003 metrics. The Commission finds that this worsening is in part due to an increase in the vegetation management backlog of 13,467 miles demonstrated by the evidence that vegetation management related outages from 2012 to 2016 have increased. While witness Simpson states that weather, aging equipment, and DER are the main drivers behind the worsening trends in reliability, the Commission concludes that vegetation management is the single biggest contributor as it accounted for almost 21 percent of outages in the test year (the number two root cause of outages behind planned outages, representing nearly 32 percent of total affected customers and almost 40 percent of total customer outage minutes), while weather only accounted for 1.82 percent (the number nine root cause of outages). The Stipulation between the Public Staff and DEC requires the Company to eliminate the backlog of miles within five years and maintain the schedule set out in the Company's 5/7/9 plan, which the Commission concludes will significantly help reduce the number of outages the Company has experienced which caused the SAIDI and SAIFI metrics to worsen in recent years.

Company witness Pirro testified regarding the Company's requested changes to its Service Regulations. He described proposed increases in the Connect Charge and the Reconnect Charge; a decrease in the returned check charge; and a reduction in the monthly facilities charge associated with extra facilities. He also described proposed changes specifying the types of activities that will be undertaken on rights-of-way, and minor changes related to the provision of service. (T 19 pp 74-76) No other party filed testimony regarding the proposed changes to DEC's Service Regulations. Therefore, the Commission finds and concludes that the amendments to DEC's Service Regulations are reasonable and should be approved.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 29

The evidence supporting this finding of fact and conclusions is contained in DEC's Form E-1, the testimony of Public Staff witness Boswell, the rebuttal testimony of Company witness Doss, and the Stipulation.

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. (E-1, Item 14) Public Staff witness Boswell commented that the Public Staff believes 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. (T 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. (T 12 p 55)

The Stipulation incorporates the Company's agreement to file an updated lead-lag study in its next rate case. No other party filed testimony on this issue. 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 FINDINGS OF FACT NOS. 30-31

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

Company witness Hager's direct testimony describes and supports the Company's Summer Coincident Peak (SCP) cost of service study. Witness Hager recommended the use of the SCP as a fair allocation of the costs to the appropriate jurisdictions and customer classes. As articulated by witness Hager, the cost responsibility of each jurisdiction and customer class should be determined on its respective demand in relation to the total demand placed on the system. (T 19 p 25)

The Company's summer and system peak occurred on Wednesday, July 27, 2016, at the hour ending 5:00 p.m. (T 19 p 25) Witness Hager testified that DEC's system peak has occurred during the summer in 22 of the last 25 years, and that the time of peak during these 22 summer peaking occurrences for the Company has ranged between the hour ending 3:00 p.m. and the hour ending 5:00

p.m. She testified that the 2016 summer peak was within the range of these past occurrences, and it is therefore appropriate to assign fixed demand-related costs to the Company's jurisdictions and customer classes based upon the SCP. (T 19 p 26)

The Public Staff historically has supported the use of the Summer/Winter Peak and Average (SWPA) cost of service allocation methodology. As noted in witness Floyd's testimony, the SWPA methodology recognizes that a portion of plant costs is incurred to meet the energy costs throughout the year, and not just at the time of the peak. (T 23 p 54) But, under the particular circumstances of this case, Public Staff witness Floyd did not object to the Company's use of the SCP methodology for determining the cost of service because the differences between the per books calculations of revenue requirement between the SCP and SWPA methodologies is immaterial on a jurisdictional basis. (T 23 p 55) In response to questions by the Commission, however, he noted that the Public Staff has not abandoned its support of SWPA. (T 23 pp 109-10)

CUCA witness O'Donnell agreed with the Company that a SCP cost of service study is the most appropriate allocation methodology for use by DEC. (T 18 pp 115-17) Likewise, CIGFUR witness Phillips testified that the SCP responsibility cost of service study is appropriate for use in this proceeding. (T 26 p 257)

The Stipulation provides 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 allocation of coal ash costs, which is included within the unresolved issues between the Company and the Public Staff. Paragraph V.B. of the Stipulation provides that neither the Stipulation nor any of its terms shall be admissible in any court or before this Commission and that the Stipulation shall not be cited as precedent by any Stipulating Party with regard to any issue in any other proceeding or docket. Paragraph V.C. of the Stipulation provides that no Stipulating Party has waived any right to assert any position in any future proceeding or docket.

The Commission recognizes that cost causation is the primary driver and support for choosing an appropriate cost allocation methodology, and that SCP and SWPA are but two methodologies that can be utilized for this purpose. The Commission also understands that there is an element of subjectivity in this choice. The Commission finds and concludes that the SCP is the appropriate cost allocation methodology, for the purposes of this proceeding, subject to the provisions of the Stipulation. In making this determination, the Commission gives substantial weight to the testimony of Company witness Hager. Although the Public Staff has traditionally supported SWPA cost allocation, it is not unreasonable for the Stipulating Parties to have agreed to the use of SCP for this proceeding. Therefore, based upon consideration of the Stipulation in its entirety, the Commission gives the Stipulation substantial weight in resolving the cost allocation issue. However, the Commission's acceptance of the SCP methodology in this proceeding shall not be precedent for and may not be cited as such in future proceedings.

Although the Commission has approved the use of the SCP cost of service allocation methodology for the purposes of this case, the Company shall continue to file annual cost of service studies based on both the SCP and SWPA cost of service allocation methodologies.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACTS NOS. 32-33

The evidence supporting these findings of facts and conclusions is contained in the Stipulation, the NCLM Partial Settlement, DEC'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. He developed the Company's proposed rates by first determining the target total proposed change in revenue requirement for each class, then designing the rate schedules and riders in each rate class to total the proposed change in the revenue target for that rate class. (T 19 p 54) Other than changes to the lighting schedules outlined in Company witness Cowling's testimony, witness Pirro's proposed rate design did not propose any substantial changes to the structure of any of its rate schedules in this proceeding. He explained in his direct testimony that the Company plans to implement rate design changes once it has deployed AMI and has updated its billing structure to better support peak time pricing rate design. (T 19 p 58)

Company witness Cowling provided testimony that outlined the Company's proposed changes to its lighting schedules. DEC proposed to lower the transition fee for customers moving from metal halide (MH) and high pressure sodium (HPS) to LED. (T 26 p 163) The Company also proposed to accelerate the schedule for replacing mercury vapor (MV) lights with LED for governmental customers on Schedule PL. (T 26 pp 165-68) The Company proposed to close Schedule NL, and discontinue Schedule FL. (T 26 pp 169-70)

Public Staff witness Floyd testified in support of the reduction in the transition fee proposed by DEC. (T 23 p 68) Witness Floyd further testified that the Company should consider an extended payment option for cities that would like to transition to LED. (T 26 p 69)

Regarding DEC's proposal to accelerate the replacement of MV lights, witness Floyd testified that the proposal would increase the cost for most lighting customers, with municipal customers under Schedule PL facing the biggest increases. (T 26 pp 70-71) Public Staff witness Floyd supported the new schedule for conversion, and made two recommendations to mitigate the increased costs associated with the change. First, he recommended the Company address the rates of return in the lighting class rate schedules to bring the rates of return within 10% of the overall rate of return for the North Carolina retail jurisdiction. (T 26 pp 72-73) Witness Floyd also recommended the Company file semi-annual reports on the progress of the MV replacement program. (T 26 p 73)

NCLM witness Fischer testified that the City of Greensboro would like to transition to LED lighting, but the Company's transition fees and rate design would make the conversion too expensive. (T 26 p 366) Witness Fischer recommended that DEC eliminate transition fees entirely and to design rate structures that provide lower rates for LED fixtures. NCLM witness Coughlan recommended spreading the loss resulting from the early transition to LED across all lighting schedules, rather than recovering the loss through a transition fee. (T 8 p 110) NCLM witness Watkins recommended the Company continue to meet with the League to discuss street lighting issues. (T 26 p 393)

In Section IV.E. of the Stipulation, the Stipulating Parties agreed to implement the rate designed proposed by the Company, subject to the following modifications:

1. 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.

2. Except for the amount of the Basic Facilities Charge, which is an unresolved issue, the Parties agree that the Company shall implement the rate design proposed by Company witness Pirro within his direct testimony, filed contemporaneously with the Company's Application in this docket, as adjusted by this Stipulation.

In the NCLM Settlement, the Company agreed to all of the following:

1. To reduce the LED transition fee for HPS to $40.00 from $54.00, and to continue to lower or eliminate the fee if applicable.

2. To allow municipalities to spread the payment for transition fees over 4 years.

3. To consolidate Schedule GL into Schedule PL as of September 1, 2018, with fees assessed for Schedule GL lights served underground.

4. To reduce the lighting rate of return to within plus or minus 10% of the overall retail average rate of return, with the resulting revenue reduction allocated to other rate classes.

5. To maintain the current LED prices and not seek to increase rates for LED fixtures.

6. To eliminate the HPS transition fee for HPS fixtures that fail.

7. To close HPS to new installations except for government customers that request the continued use of HPS for appearance reasons.

8. To transition governmental floodlights to Schedule GL until September 1, 2018, when the governmental floodlights will be added to schedule PL.

9. To allow governmental non-floodlight service that requires a new pole or undergrounding, as of September 1, 2018, to pay the current Schedule GL

pole and undergrounding fees of $6.49 per pole and $4.62 for up to 150 feed of underground.

10. To continue allowing customers the option to prepay initial the capital costs of poles and underground wiring when Schedule GL is consolidated with Schedule PL.

11. To file semi-annual conversion progress reports regarding the conversion of MV fixtures to LED.

12. To continue meeting with the NCLM and other interested parties to discuss outdoor lighting.

Based on the testimony of the witnesses, as well as the Stipulation, and the NCLM Partial Settlement, the Commission finds that the rate design provisions of Section IV.E. of the Stipulation, as modified by the NCLM Partial Settlement, are just and reasonable to all parties in light of all the evidence presented.

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

The evidence supporting these findings of fact and conclusions is contained in the Application and Form E-1 of DEC, the testimony and exhibits of the DEC and Public Staff witnesses, the Stipulation and the NCLM Partial 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 out 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 NCLM Partial 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 FINDINGS OF FACT NOS. 36-38

Along with its Application For Adjustment of Rates and Charges to Electric Service filed in this base rate case, the Company also filed a Request to Cancel the Lee Nuclear Project in Docket No. E-7, Sub 819 (Sub 819). On October 18, 2017, the Commission issued an order, among other things, consolidating Sub 819 with the rate case docket.

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. (T 10 p 182) In March 2006, DEC announced that it had selected the Lee site to evaluate for possible nuclear expansion. (T 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, in which the Commission determined 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, G.S. 62-110.7 went into effect, which provided 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 G.S. 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.

Under 62-110.7(a), the Commission must approve a decision to incur project development costs if they are shown to have been reasonably and prudently incurred; however, the Commission does not consider the reasonableness or prudence of any specific activities or items of costs until a rate case proceeding. G.S. 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, G.S. 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, 12 years in this case. It should be noted that while G.S. 62-110.7(c) provides for rate base treatment of project development costs and therefore includes a return, G.S.62-110.7(d), applicable to cancelled projects, only requires amortization of the costs and does not mandate a return.[17]

Mr. Fallon testified that on December 7, 2007, DEC filed an Application for Approval of Decision to Incur Continued Generation Project Development Costs. (T 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

[17] 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 (AFUDC), which is included in the definition of "project development costs" set forth in G.S. 62-110.7(a).

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. (T 10 p 187) The Commission approved DEC's request on June 11, 2008. (T 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. (T 10 pp 188-89) The Commission did not approve DEC's request as filed, but ordered on August 5, 2011 (2011 Order) 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). (T 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. (T 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 approval orders after the 2011 Order.

Mr. Fallon testified that the Company incurred costs for the development of the Lee Nuclear Project of approximately $542 million through June 30, 2017. The costs are composed of the following categories: 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. (T 10 p 178; T 11 p 19) He stated that in order to "maintain the status quo", DEC exceeded the cap set in the 2011 Order in 2013. (T 10 p 192) Specifically, Mr. 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. (T 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 Mr. 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.*)*

Mr. Fallon noted that the Company submitted a COLA with the NRC for two Westinghouse AP1000 Pressurized Water Reactors on December 13, 2007. (T 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. (T 10 p 192) Mr. Fallon stated that on December 19, 2016, the NRC issued COLs for Lee Nuclear allowing DEC to construct the units and operate them for 40 years. (Id.) The licenses are renewable for an initial 20-year period and possibly a second 20-year period. (T 10 p 181) Mr. Fallon stated that under the terms of the COL, DEC is not compelled to build and operate the nuclear plant. (Id.)

Mr. 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. (T 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. (T 10 p 193) In addition, Mr. Fallon noted that having the COL for Lee Nuclear Project would reduce the lead time required to license new nuclear plant at the site. (Id.) Mr. 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. (T 24 pp 61-62)

In regard to the request to cancel the Lee Nuclear Project, Mr. 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. (T 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. (T 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.) Mr. 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. (T 10, p 198) Therefore, due to these uncertainties and risks, as well as projected low natural gas prices and uncertainty about carbon emission costs, Mr. Fallon testified that the Company believes 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, as well as monitor the Westinghouse bankruptcy and the progress of the Vogtle Project. (T 10 pp 198-99) Mr. 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. (T 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. (T 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, Dr. Diaz stated DEC had chosen the optimal path to pursue licensing by using the NRC's new nuclear reactor licensing protocol pursuant to 10 CFR Part 52 Rule (Part 52) (T 10 p 223), but that significant time was necessary due to Part 52 being untested. (T 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.)

Dr. 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 (T 10 pp 235-36), the Waste Confidence Rule (T 10 pp 236-37), the Fukushima Dai-ichi accident (T 10 pp 238-39), and the new Seismic Source Characterization (T 10 p 240). Additionally, delays occurred as DEC updated its COLA from Rev 16 to Rev 19 of the AP1000 (T 10 pp 241-42), changed the location of the reactor based on it improving reactor building stability and being more economical to construct (T 10 pp 242-43), added a make-up pond for cooling water due to the limited water in the main cooling source (T 10 pp 243-44), and amended the COLA to revise the cooling tower design. (T 10 p 244) Dr. Diaz testified that he believed that DEC acted prudently in making each of these changes and thus the resulting delays were reasonable. (T 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 Dr. Diaz concluded DEC had managed in a reasonable and prudent manner. (T 10 pp 245-48)

Dr. Diaz 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. (T 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. (T 10 pp 250-51) Dr. 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. (T 10 p 253) He further determined that the project costs incurred were reasonable and prudent. (T 10 p 234)

DEC witness McManeus testified that the Company was proposing to amortize the accumulated construction work in progress (CWIP) balance related to the Lee Nuclear Project. (T 6 p 257) In her direct testimony, Ms. 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 nondepreciable 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." (T 18 p 51)

Tech Customers' witness Kee testified that DEC should only be allowed to recover the North Carolina share of costs, including AFUDC, incurred through December 31, 2009, up to the limits of the first two project development orders in Sub 819. (T 18 p 205) As DEC did not receive approval from the Commission to incur project development costs in 2010, Mr. Kee contended that they were not recoverable. (Id.) He recommended that the Commission deny recovery of any costs incurred on or after January 1, 2011, because DEC had failed to show that the activities were necessary to maintain the status quo as required by the 2011 Order, or allow recovery only for what he considers Type 1 activities, costs in the COLA Preparation, NRC Review and Hearing Fees, and Post COL categories, related to the NRC review of the LEE COLA. (T 18 pp 182, 205) Mr. Kee further proposed that the Commission disallow any recovery, including AFUDC, above the cap set in the 2011 Order. (T 18 p 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. (T 23 pp 31-32) The Public Staff also reviewed the activities and costs internally. (T 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. (T 23 pp 32-33) Mr. 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. (T 23 pp 33-34) This recommendation results in a disallowance of $507,009 on a system basis, exclusive of AFUDC. (T 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. (T 22 p 100) Based on his review, Mr. 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. (T 22 p 101) Based on discussions between DEC and the Public Staff, Mr. 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. (T 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 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. (T 26 p 140) She argued that the Commission had found in past cases that this treatment equitably allocated the loss between the utility and customers, and that customers should not bear all the risk of cancelled plant, as had occurred with Lee Nuclear. (Id.)

In his rebuttal testimony, Dr. Diaz disagreed with Mr. 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 have the Lee Nuclear option available to meet the dates for need projected in DEC's IRPs. (T 26 p 181) He noted that DEC could not have obtained the COL without exceeding the limits in the 2011 Order. (T 26 p 182) Dr. Diaz further testified about the value of the COL obtained by DEC. (T 26 pp 186-88)

On rebuttal, Company witness Fallon testified that the Company did not oppose the recommendation of Mr. Maness to end the accrual of AFUDC for Lee Nuclear at December 31, 2017. (T 24 pp 32, 33) In regard to Mr. Metz's proposed disallowance for the costs associated with the architectural and engineering of a visitors' center, Mr. Fallon explained the reasons why DEC sought to construct a visitors' center as one of the buildings with early design work, but conceded that Mr. Metz's conclusion to recommend a disallowance for these costs was reasonable. (T 24 p 34)

Mr. Fallon did oppose 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 Ms. 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. (T 24 pp 34-35) Mr. Fallon pointed out that G.S.62-110.7 did not prohibit DEC from receiving a return on the unamortized balance of prudently incurred costs. (T 24 p 36) He argued that Ms. 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. (T 24 pp 37-39) Mr. Fallon also detailed the steps the Company took to mitigate the risks of the project. (T 24 p 39)

In regard to the testimony of Tech Customers' witness Kee, Mr. Fallon disagrees with the contention that all nuclear development costs must be approved or authorized in advance under G.S. 62-110.7 to be recoverable. (T 24 p 40) He noted that while the 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. (T 24 p 41) Mr. Fallon contended that utilities are permitted, but not required, to seek approval of the decision to incur project development costs under G.S. 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.) 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. (T 24 p 44) In order to maintain this active COLA status, Mr. Fallon explained that DEC had to continue its permitting, pre-construction, engineering, design, construction planning, and operational planning activities to maintain the status quo. (T 24 p 45)

On cross examination, Mr. Fallon identified Tech Customers Fallon Rebuttal Exhibit 1 as an internal presentation made in February 2012 to the Company CEO's staff by Mr. Fallon and the nuclear development staff regarding the future of the Lee Nuclear Project. (T 24 pp 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. (T 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.[18] (T 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. (T 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. (T 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. (T 24 pp 65-66)

Mr. Fallon testified that DEC had exceeded the spending cap set in the 2011 Order in the second quarter of 2013 and was outside of the authorization to incur nuclear project development costs given by the 2011 Order under G.S. 62-110.7. (T 24 p 66) He agreed that one of the purposes of G.S. 62-110.7 was to help alleviate some portion of the risk that certain costs incurred for nuclear project

[18] 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.

development activities may be found imprudent. (T 24 p 71) Mr. 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. (T 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. (T 24 p 75) Mr. Fallon argued that the Harris Nuclear and Lee Nuclear projects were different because DEC had sought approval under G.S. 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. (T 24 pp 75-77) Finally, Mr. Fallon admitted 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. (T 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 visitor's center from the Lee Nuclear costs or Public Staff witness Maness to remove AFUDC for the months after December 2017. (T 26 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 accumulated deferred income taxes from rate base, thereby preventing the Company from earning a return on the unamortized balance. (Id.) Ms. McManeus argued that the Commission should consider that the Lee Nuclear project costs were financed by investors and should appropriately be in rate base. (T 6 p 311)

According to Ms. 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, Ms. McManeus noted that the decision to allow the Company to earn a return on cancelled plant was within the Commission's discretion. (T 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. (T 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.)

Conclusions on Lee Nuclear

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. DEC did not contest either of these two proposed adjustments.

In regard to the adjustments proposed by Tech Customers' witness Kee to disallow the costs incurred in 2010 and in excess of the limit set in the 2011 Order, the Commission finds that this recommendation appears to be based on a misreading of G.S. 62-110.7. First, G.S. 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 G.S. 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 to be considered in this proceeding. G.S. 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 G.S. 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 G.S. 62-110.7. The Commission further disagrees with Mr. Kee that what he categorizes as Type 2 costs should be disallowed as they are 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.

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 Mr. 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.[19]

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[19] While G.S. 62-110.7(d) contains the language "if the public utility is allowed to cancel the project", the Commission finds that this language contemplates that a utility would have first received approval of the project by the commission in the state where the generating unit is to be located, as well as any necessary approvals by other commissions in the state(s) where customers who will be served by the generating unit are located, e.g. G.S. 62-110.6. Under North Carolina's applicable CPCN statute, G.S. 62-110.1(e), cancellation of construction by a recipient of a CPCN must first be approved by the Commission; however, cancellation of a project in another state for which the Commission has issued a determination of need under G.S. 62-110.6 does not require Commission approval. *See* G.S. 62-110.6(e). The PDOs issued in Sub 819 never approved the Lee Nuclear Project, but only the decisions to incur certain costs for certain periods. As there has been no approval of the project by this Commission, the language of G.S. 62-110.7(d) regarding "permission to cancel" is inapplicable.

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. Utilities Commission v. Thornburg*, 325 N.C. 484, 385 S.E.2d 463 (1989). *See also*, *State ex. rel. Utilities Commission v. Thornburg*, 325 N.C. 463, 480-81 (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. It is true that in most circumstances, a utility has been allowed to recover expenses it has prudently incurred in pursuit of its business activities, even when the expenses do not lead to a successful result. However, the losses resulting from abandonment of a proposed nuclear generating plant are treated differently, because of their much greater magnitude in comparison with typical utility expenses. The costs of constructing a nuclear plant are greater than any other expense a utility is likely to incur. 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 rough sharing 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 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 Mr. 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 G.S. 62-110.7. While G.S. 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 G.S. 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 Mr. Fallon that having obtained a COL should merit shifting of 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 *State ex rel. Utilities Com'n v. Thornburg*, 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 unamortized balance); *Order Approving Stipulation and Deciding Non-Settled Issues*, 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 *Order Approving Partial Rate Increase*, 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 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.

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 amortized balance.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 39-41

The evidence supporting these findings of fact and conclusions can be found in the direct testimony of Public Staff witnesses Robert Hinton and Michael Maness and the rebuttal testimony of Company witnesses Stephen De May and David Doss.

In his testimony, Public Staff witness Hinton described the NDTF and the funding model that ensures sufficient funds are available to decommission nuclear units. He testified that the Nuclear Regulatory Commission requires funding of NDTFs or other financial assurance for nuclear facilities to cover the cost of decommissioning. NDTFs are funded by ratepayers and segregated into qualified and non-qualified trust funds set aside by utilities exclusively for nuclear decommissioning. (T 22 p 247)

Witness Hinton further testified that the Commission has adopted Guidelines for Determination and Reporting of Nuclear Decommissioning Costs (Guidelines) in Docket No. E-100, Sub 56 (the Decommissioning Docket).[20] The Guidelines require utilities to perform and issue site-specific nuclear

[20] The Commission has taken judicial notice of this docket in this rate case proceeding.

decommissioning cost studies at least once every five years and provide for the filing of a funding report related to the cost studies. The purpose of the studies and reports is to ensure that the NDTFs of the utilities are being efficiently funded at a sufficient level to decommission the nuclear units of the utilities. DEC filed its most recent Decommissioning Cost and Funding Report (DCF Report) regarding its nuclear decommissioning cost study on October 10, 2014. (T 22 pp 247-48)

Witness Hinton described the funding model that ensures sufficient funds are available to decommission nuclear units. The funding model targets a site specific estimate of the future costs to decommission the plant site. The key inputs in the model are the current balance of the funds collected, the projected annual earnings rates on the funds, and the projected inflation or escalation rates that yield the future cost of decommissioning. Other assumptions that tend to have less of an impact of the funding model include whether one includes a reduction in the rate of return during the decommissioning period to provide enhanced certainty of cash flows and the level of portfolio turnover within the fund. Once the future expense levels are ascertained, DEC incorporates an investment strategy that is designed to generate sufficient earnings to meet this expected future expense. The amount of funding required over the approximate 25 years of decommissioning is levelized with an annuity calculation. (T 22 p 248)

Witness Hinton noted that unlike DEC's previous rate case, in which the Company requested an increase in decommissioning expense, the Company is not seeking to recover any decommissioning expenses in this case. On December

23, 2014, DEC filed a notice in the Decommissioning Docket that the Company thought it was reasonable to eliminate the amount of nuclear decommissioning expense. The filing noted that the NDTF had experienced investment rates of return significantly higher than what was expected over the long term. According to witness Hinton, DEC was referring to the above average returns for DEC's qualified funds and non-qualified funds, respectively, over the then most recent five-year period (2009-2013). Another possible factor was the above average earned returns for DEC's qualified funds and non-qualified funds over the prior ten years (2004-2013). DEC's annual earned returns as of June 30, 2017 and for the past 25 years for its qualified and non-qualified funds were presented in witness Hinton's Confidential Exhibit JRH-2. (T 22 pp 249-50)

According to witness Hinton, in this case, DEC utilized a projected after-tax rate of return on the qualified fund of 4.3% and the escalation rate of 2.4%. DEC utilized an after-tax projected rate of return on its non-qualified funds of 3.8%. In addition, the funds are de-risked as the fund approaches the final five years of the decommissioning period, which lowers the projected qualified after-tax returns to 1.8% and 1.4% for the qualified and non-qualified funds, respectively. (T 22 pp 249-51)

Witness Hinton noted that actual earned returns on the qualified and non-qualified funds have been significantly greater than the projected 4.2% and 3.8% annual rates used in the funding model and this difference will likely cause the NDTF to continue to generate funds that are in excess of the projected costs.

Witness Hinton testified that the results of the funding model show that even when utilizing these lower than historically experienced rates of return, DEC's NDTF is overfunded by $2.35 billion. He recommended that the excess funds be returned to ratepayers. According to the Company, this can be accomplished by reducing NC retail expenses by approximately $29.1 million[21] per year, which would effectively remove the excess funding. (T 22 pp 249-52, 274)

Witness Hinton testified that there are sufficient regulatory protections to avoid any significant under recovery in the NDTF as a result of his recommendation. The NDTF is reviewed every five years by the Commission in the Decommissioning Docket, and if it became apparent that the NDTF is underfunded, the Commission can take appropriate action. (T 22 pp 252-53) Witness Hinton noted in response to Commission questions that in DEC's last rate case the Public Staff agreed not to oppose a deferral if it were to be found that the NDTF was underfunded. (T 22 p 321) He also testified that historically the earning rates of return for DEC's NDTF are greater than the 4.3% for the qualified fund and 3.8% for the non-qualified fund assumed by DEC, as shown in witness Hinton's Confidential Exhibit JRH-2. The fact that the pattern of earned rates of return on the funds on the decommissioning funds calculated over most any reasonable period of time tends to be significantly above the projected returns provides for a

[21] Corrected from $19.4 million N.C. Retail in witness Hinton's supplemental testimony [T 22 p 260].

significant degree of conservatism that should lead to a continuation of the over funding in the future. (T 22 pp 252-53)

On cross-examination by counsel for NCWARN, witness Hinton acknowledged that an NRC document indicated that 17 nuclear plant sites had been decommissioned. Witness Hinton testified that as more and more plants are actually decommissioned, more information is being gathered, resulting in a higher confidence associated with decommissioning cost estimates. (T 22 pp 286-87)

Witness Hinton further testified in response to cross examination questions from the Company that the NDTF is the customers' money. The fund has overearned more than projected due, in part, to the fact that projections are too conservative. The overfunding is not going to go away; as long as the model projects a low rate of return, the earnings will continue to grow larger and larger. (T 22 pp 307-08)

Regarding witness De May's claim that a projected inflation rate of 3.1% would wipe out the excess funds, witness Hinton maintained that a 3.1 percent inflation rate would lead to a nominal return of 5.1 percent or higher. Thus, even if inflation were to move to 3.1 percent, the excess funds would still exist. (T 22 p 309)

Public Staff witness Maness proposed a regulatory accounting method to accomplish the advancement of the NDTF overfunding to ratepayers while protecting shareholders. He explained that the NDTF has been, and will be, provided by the ratepayers over each nuclear unit's life, and will earn a return from the NDTF's investments until expended for actual decommissioning. If the decommissioning periods end without all of the funds being expended, it is appropriate and reasonable to assume that the leftover funds, having been supplied by the ratepayers, will be fully returned to them in such fashion. In other words, any excess funds take on the character of a regulatory liability, which represents funds due to the ratepayer at a future date. (T 22 p 105)

Witness Maness further explained that because under the Public Staff's recommendation, the shareholders may be required to temporarily provide excess funds to the ratepayers prior to decommissioning, the ratepayers would essentially "give up" their claim on those funds at the time decommissioning is completed. He stated that it is important to note that the Public Staff's recommendation is not an acceleration of what one would expect to occur, leaving aside the question of whether funds can currently be removed from the NDTF. Rather, the expense reduction recommended by witness Hinton is simply the result of calculating nuclear decommissioning expense using the models that DEC and the Commission have used for decades, without regard to whether funds can be removed from the NDTF. (T 22 p 106)

Witness Maness recommended that the Company be allowed to establish a regulatory asset for the difference between the credit nuclear decommissioning expense recommended by witness Hinton and the zero amount of nuclear decommissioning expense proposed by the Company, adjusted appropriately for income tax effects. This regulatory asset would increase by the expense differential each year, at least until the Company performs its next nuclear decommissioning study and cost estimate, at which time it might need to be adjusted. In this manner, if there are in fact excess funds left over when decommissioning is completed, a portion of those funds can be used to satisfy the regulatory asset, and not "double-returned" to the ratepayers. Witness Maness testified that it is not certain that the regulatory asset will survive until decommissioning is completed; if, over time, expectations regarding decommissioning costs, future earnings, discount rates, or other items changes, it is possible that annual funding requirements will increase. If nuclear decommissioning expense, calculated and charged to expense in a manner that takes into account the credit decommissioning expense recommended by the Public Staff in this proceeding, exceeds nuclear decommissioning expense calculated given the actual NDTF balance, a portion of the extra expense charged as part of cost of service should be used to satisfy the regulatory asset beginning at that time. (T 22 pp 106-07)

Witness Maness addressed two concerns expressed by the Company regarding his recommendation. The first is whether the Public Staff's recommendation constitutes a phase-in plan. Regarding this concern, witness Maness testified that the Public Staff recommendation is not being made for the purpose of "phasing in" the Company's proposed rate increase (or increasing a rate decrease), nor is it in any way directly related to the bringing into service of the Lee combined cycle facility. It is, instead, an attempt to determine nuclear decommissioning expense in a manner similar to the way nuclear decommissioning expense has been determined for many years and many rate cases, taking into account the fact that funds cannot be removed from the NDTF at the present time. (T 22 pp 108-09)

Witness Maness described the Company's concern that because decommissioning activities will not be completed and excess funds distributed until many years into the future, its GAAP auditors may not be willing to express an opinion that the regulatory asset is "probable of recovery," and thus may not allow recognition of the asset in the GAAP financial statements. Witness Maness stated that it was his belief that should this Commission approve the establishment of my recommended regulatory asset, the Commission would intend that it be fully recovered through recognition in cost of service, and, as appropriate, through rate changes approved as part of general rate cases, all pursuant to the North Carolina general statutes the Commission's rules and regulations, and its accounting and ratemaking policies and practices. He testified that the actions of this Commission do have economic substance. Witness Maness stated that during his 35-year employment with the Public Staff, he had never become aware of any time that the Commission has failed to appropriately preserve the economic substance of regulatory assets which it has approved. Under the rules of GAAP, and using their own professional judgment, the Company's external GAAP auditors may reach a conclusion that the regulatory assets approved by the Commission may not be recognizable for purposes of the financial statements generated for investors. However, witness Maness does not believe that the Commission should substitute the GAAP auditors' judgment regarding GAAP financial statements for investors for its own judgment regarding appropriate and reasonable rates for N.C. retail ratepayers. It is the Commission's responsibility to determine those rates; the purpose of financial reporting is simply to reflect the Commission's exercise of that responsibility. In summary, the Public Staff's recommendation regarding nuclear decommissioning expense is reasonable for the ratepayers, and using a regulatory asset or assets under the Commission's own accounting rules is also sufficient to protect the shareholders' interests. (T 22 pp 109-11)

On cross examination, witness Maness testified that while the Public Staff did not recommend any changes to the Company's decommissioning cost and funding activity in 2015 in the Decommissioning Docket, the Company was not in a general rate case at the time. (T 22 pp 196-97, 199) He asserted that there is a difference between the Company voluntarily proposing a rate reduction through a rider outside of a rate case and the Public Staff making such a recommendation, which could easily transform into a general rate case proceeding or a show cause proceeding. (T 22 p 198) He stated that the Public Staff did not make a recommendation then, but we are two years down the road, and the overfunding is still there, and it is definitely very material and significant to the customers of DEC. (T 22 pp 199-200) He further testified that he regards the Public Staff's recommendation more as an advance of monies that cannot be removed from the NDTF at this time than as a "loan" to the ratepayers. If they could be removed from the NDTF, he did not know that there would be any argument about reducing nuclear decommissioning expense, as the calculations done to establish the $29 million annual credit that the Public Staff is recommending are done exactly the same way as calculations that have been done previously that recommended an increase. (T 22 p 203)

Witness Maness did not agree that the Company would be writing off the advance of funds. All other things being equal, if there are no changes in the projections of nuclear decommissioning costs or the fund's balances, the eventual amount returned to the ratepayer will be the same whether or not the Public Staff's recommendation is adopted. There will be no long-term loss to the Company as a result of adoption of the Public Staff's position. There would just be an advance, which then, when nuclear decommissioning was over, the Company's shareholders would receive full use of the leftover funds to offset the regulatory asset that he recommends. (T 22 p 205)

Regarding GAAP rules, witness Maness testified that he fully supports that for purposes of presenting its financial statements to investors, the Company comply with generally accepted accounting principles. However, for the Commission's ratemaking decisions, that has to be balanced against what is right for the ratepayers and what is fair and reasonable in rates. He does not believe that the Commission should put GAAP requirements over its own determination of what is fair and reasonable, no matter what the outcome might be in terms of the GAAP financial statements. (T 22 p 206) If there were no impediment to removing amounts from the NDTF, he found it hard to imagine that the Company would have much disagreement with going ahead and reducing rates now, especially given that every time the nuclear decommissioning cost and funding studies have indicated decommissioning expense should go up, the Company has had no hesitation about having rates increased to collect that money. (T 22 p 207)

Witness Maness pointed out that the Company is currently carrying a number of long-term regulatory assets on its books, as reflected in the Company's 2016 Form 1. There is a regulatory asset related to income taxes. It does not specify how long that regulatory asset is going to remain on the books, but it is credible to expect that some of that balance, which at the end of 2016 was approximately $871 million, is, in fact, long term. There is also a regulatory asset related to qualified pensions. Again, it does not indicate when that asset is expected to be resolved, but it is reasonable to think that some portion of that asset is long term. He described regulatory assets on the books related to Dan River (39 years), Cliffside 6 (35 years), and McGuire and Oconee deferred costs (43 and 28 years, respectively). Witness Maness did not know exactly when these regulatory assets would be resolved, but there was no indication that those assets are not being allowed to be recorded. (T 22 pp 210-13) In this case, while the Company has discussed the Public Staff's recommendation regarding the NDTF with its auditors, an actual audit has not taken place. Further, while the regulatory asset might not be able to be recognized, that means the Company's income in the near years would be lower than what the Commission would assume for purposes of the books and records of the Company. However, it balances out, and in later years, the Company's income would be higher. There would be no long-term loss to the Company. In addition, the NDTF is examined every five years, and adjustments could be made as a result of those studies or in later rate cases that would perhaps resolve the regulatory asset even before the end of decommissioning if projections of cost and funding change. (T 22 p 212)

On redirect, witness Maness stated that he was not aware of any North Carolina commission or any case law that would conflict with his proposal. To the extent there's overfunding for nuclear decommissioning costs, that money has been provided by customers, supplemented by earnings on those funds. The proposal to create a regulatory asset would deliver the overfunding back to ratepayers at an earlier date than the Company's proposal and would improve intergenerational equity. (T 22 pp 220-21)

In response to a question from Commissioner Brown-Bland, witness Maness explained the purpose of Maness Cross Examination Exhibit 3, which was a Joint Report filed in 2002. The report contained certain stipulated items between the Public Staff, Carolina Power & Light, Duke Power, and Dominion North Carolina Power. In the report, the parties agreed to address the disposition of any decommissioning funds remaining after paying the necessary decommissioning costs when and if they occur. Witness Maness testified that the objective of having the five-year studies and looking at funding in rate cases is to hopefully minimize the amount of the true-up that would occur at the end. If the Public Staff's position is taken and no other projections change over the years, we will be, in fact, minimizing the true-up at the ends of the day. But that does not mean that there will be no true-up. Mr. Maness did not take the 2002 report to mean that one would never make an adjustment to change nuclear decommissioning expense simply because it will all be trued up in the end. Prior adjustments have been made to nuclear decommissioning expense, which served the dual purpose of intergenerational equity (charging the right amount in the right years to the right generations of ratepayers) and minimizing the amount of the true-up at the end. He agreed that the 2015 rate decrement reflected in Maness Cross Examination Exhibit 2 was an example of the Company itself not waiting for a true-up time period, but instead recommending a decrease. (T 22 pp 229-30)

In his rebuttal testimony, Company witness De May disputed the conclusion of Public Staff witness Hinton that the NDTF is overfunded. He testified that witness Hinton had only considered the funding level from a projected value perspective. He contended that this approach is incomplete. He testified that the Company looks at the question from a number of different and additional perspectives, including projected value (which is the $2.35 billion amount referred to by witness Hinton), current value (which compares the current cost of decommissioning with the current NDTF balance), and probabilistic analysis. Witness De May testified that based on these various measures of funded status, the NDTF is adequately funded to meet the Company's projected future decommissioning obligations, but is not "overfunded" to the point where one could prudently contemplate returning funds to customers even were it legally possible to do so.

Witness De May further testified that NRC and IRS regulations required NDTF funds only be used for decommissioning-related activities. A withdrawal for other purposes, including return to customers, would be impermissible. He characterized witness Maness' proposal as a "forced loan" from the Company to customers and that there is no ratemaking mechanism that could force the Company to make a loan to its customers.

Witness De May stated that he is concerned that returning the projected excess funds to ratepayers could lead to the underfunding of the NDTF in the future. He stated that the NDTF has experienced higher than expected returns recently, and the escalation rate assumption has remained modest, both of which have contributed to favorable results. These factors will change over time and any deviation in these assumptions will impact the NDTF's projected fund level. Model return assumptions are based on impartial financial institution long-term capital market return assumptions. Changes in those forecasts, as well as changes in escalation forecasts and other assumptions, such as decommissioning start dates, will all impact the future NDTF. In his judgment, while the NDTF is currently adequately funded, uncertainty over market returns and escalation rates indicate it is not prudent risk management to return funds to customers at this time, even were it legally permissible to do so.

During cross examination, witness De May discussed the cost and funding reports that the Company and other utilities are required to develop and file at the state and federal levels, summarized on De May Public Staff Cross Examination

Exhibit 1. Witness De May agreed that as far as the NRC is concerned, DEC's trust fund is adequately funded, and the Company does not anticipate collecting additional funds from customers. (T 4 pp 567-68) He conceded that the average earnings for the NDTF shown on Public Staff witness Hinton's Confidential Exhibit 2 are greater than the Company's projected annual earnings. (T 4 p 569) The Federal Energy Regulatory Commission, or FERC, also requires an annual fund report. (T 4 pp 569-70) At the State level, under guidelines adopted by the Commission in the Decommissioning Docket, three reports are required: a decommissioning cost study report (every five years); cost and funding reports (filed after the cost study reports); and decommissioning fund reports. (T 4 pp 574) Witness De May agreed that nuclear decommissioning is also reviewed during general rate cases because funding for nuclear decommissioning is collected through rates. (T 4 p 575) He agreed that given the list of cost and funding reporting, it is fair to say that the funding of nuclear decommissioning is scrutinized on a regular basis at the federal and state levels.

Witness De May also acknowledged that the Commission just examined Duke Energy Progress' NDTF in its recent rate case, where DEP requested annual funding of $19.6 million to address a projected shortfall in DEP's NDTF. (T 4 p 576) According to De May Public Staff Cross Examination Exhibit 6, which was a response to a Public Staff data request, when asked whether the methodology used by DEP to determine there was a shortfall and that additional funds were needed is the same methodology used by DEC and relied upon by Public Staff witness Hinton to identify the $2.4 billion in overfunding, the Company's response was that the methodologies are consistent and identical. (T 4 p 577) Witness De May agreed that in determining the funding levels necessary to ensure that the trust fund for DEP is fully funded, DEP, and ultimately the Commission, looked at the projected value of the trust fund, just like Mr. Hinton has done in this case in making his determination that the DEC trust fund is overfunded. (T 4 pp 577-78)

Witness De May was also presented with De May Public Staff Cross Examination Exhibit 8, a list of funding on a current basis for the five units that DEC wholly owns and for the two Catawba units that DEC partially owns, as of December 31, 2016. (T 4 p 583) Witness De May acknowledged that Oconee 1, the first unit scheduled to be decommissioned, on a current dollar basis, is 104.4 percent funded. He agreed that the fund continues to increase the closer you get to decommissioning. (T 4 pp 584-85)

Witness De May agreed that this case is not the last time the Commission is going to look at nuclear decommissioning expense for DEC. In response to the question, "So if the Commission were to adopt the Public Staff's recommendation, and it turns out that some of these returns were not what was expected, or the escalation rate was higher than your Company's number that was used to make this projection, the Commission could address that in future cases, could it not?" Witness De May responded, "The Commission can do, really, anything it wants in that regard, subject to the legality of it, yes." (T 4 pp 590-91)

In his rebuttal, Company witness Doss addressed the regulatory accounting recommendation of Public Staff witness Maness. He testified that he disagrees with Mr. Maness that the Public Staff's proposed mechanism (i.e. establishment of a regulatory asset) would protect shareholders. (T 12 p 59) While the Company agreed with witness Maness that an order from the Commission carries great weight in accounting matters, the Company is still required to adhere to GAAP in its financial reporting to the Securities and Exchange Commission (SEC) and shareholders. The GAAP guidance regarding regulatory assets is contained in the Accounting Standards Codification (ASC) 980-340-25-1, which states that the "rate actions of a regulator can provide reasonable assurance of the existence of an asset." However, it also states that it must be "probable that future revenue in the amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes." Witness Doss testified that the term "probable" is defined in ASC 450-20-20 as "the future event or events are likely to occur." He contended that in the present case, there is no such direct visibility to collection beginning at any point in the near future. (T 12 pp. 59-60)

Witness Doss testified that based on discussions with its independent auditor, the Company believes that the regulatory asset proposed by Public Staff witness Maness would not be considered probable of recovery under GAAP. The Company would be required to immediately expense the cost of the loan in its GAAP financial statements, thereby reducing the earnings per share realized by the shareholders. (T 12 pp 60-61)

On cross-examination, witness Doss acknowledged that GAAP sets accounting rules only for the Company's financial statements prepared for investors, not the rules for financial report to regulatory commissions, and certainly not for those commissions' ratemaking actions. (T 12 p 93) He agreed that Commission Rule R8-27 generally prescribes the FERC Uniform System of Accounts, or USOA, not GAAP as the accounting standard that DEC must follow for Commission accounting purposes and that the rule also allows the Commission to depart from FERC USOA if it so wishes. (T 12 p 94) He also agreed that even if GAAP does not allow the Company to initially recognize a regulatory asset for investor financial statement purposes, the underlying income is still recognized when the promised funds are actually received by the Company. (T 12 p 95)

Witness Doss further acknowledged regarding the Public Staff's proposal that if the most recent cost of funding analysis of decommissioning expense proves to be accurate, ratepayers will not have to pay money back to the Company because the Company will be able to access sufficient funds in the NDTF at the end of decommissioning. If the Commission goes along with the Company's position, ratepayers will have to wait until decommissioning is completed to receive the excess funds collected from them. Further, if the cost-of funding analysis proves to be incorrect, under the Public Staff's recommendation, the Commission will have the opportunity to make adjustments and corrections to the amounts returned to or collected from ratepayers. (T 12 p 97)

Witness Doss went on to concede that while the Commission has been tough but fair, the Company has seen that the economic substance is generally preserved for regulatory assets. (T 12 p 98) In addition, were the North Carolina

General Assembly to consider a different form of regulation, the Company would bring to the General Assembly's attention the fact that there were regulatory assets and liabilities that would need to be taken into account. (T 12 pp 102-03)

Based on the evidence presented, the Commission finds DEC's NDTF is overfunded. The methodology used to determine that the Company's NDTF is overfunded is the same methodology that has been used by this Commission and utilities for decades in determining the appropriate level of funding for NDTFs. Recently, DEP used this same methodology to determine that DEP's NDTF was underfunded and recommended (and this Commission approved) an increase in DEP's revenue requirement to collect the additional funds from ratepayers. It is disingenuous for the Company to argue that this same methodology cannot be used to calculate the level of overfunding in DEC's NDTF.

It is undisputed that the actual rates of return for the qualified and non-qualified funds from 1993-2017, as well over most periods of time, have produced returns for the Company's NDTF that are significantly greater than the 4.3 percent and 3.8 percent projected rates of return for the qualified and non-qualified funds that are incorporated in DEC's current funding model, as shown in witness Hinton's confidential Exhibit JRH-2 attached to his direct testimony.[22] The Commission

[22] The Commission notes that DEC's projected rates of return for its trust fund are conservative when compared to Dominion Energy North Carolina's projected returns on its NDTF investments as described in the Public Staff's January 14, 2016 Report in the Decommissioning Docket.

finds, therefore, that not only is the NDTF is overfunded, but also that the overfunding is likely to continue.

Having determined that DEC's NDTF is overfunded and that the overfunding is likely to continue as contended by the Public Staff, the question becomes what, if anything can or should be done to return that overfunding to ratepayers on a timely basis. Were the Commission to do nothing, ratepayers would have to wait 50 years or longer until decommissioning is complete before the excess would be returned to them. The Commission finds that this would result in intergenerational inequities that can be avoided by Commission action now. On the other hand, no one disputes that IRS and NRC rules and regulations prohibit access of funds from the NDTF for the purpose of returning the excess to ratepayers. The Commission finds and concludes that the accounting mechanism proposed by Public Staff witness Maness strikes the right balance. By reducing the Company's revenue requirement by $29 million, ratepayers who have been paying into the NDTF would receive the benefit of the return of the overfunding. By establishing a regulatory asset with a return, the Company's shareholders, in the long term, will be held harmless and made whole.

The Commission rejects the notion that the accounting mechanism proposed by the Public Staff is tantamount to a "forced loan" as argued by Company witness De May. Mr. De May's argument disregards the fact that the funds are, and have always been, <u>customer funds</u>. The funds were paid via utility rates by customers over the course of many years. If one uses the "forced loan" analogy, it is more appropriate to describe the funds paid into the NDTF as a "forced loan" by customers, since those funds are contributed well in advance of their actual use and any unused amounts will flow back to customers. The proposed accounting mechanism simply returns a portion of the overfunded amount to the ultimate owner immediately. Requiring customers to wait for decades will deny many customers their fair share of the remaining balance as they will have moved, died, or otherwise ceased to be paying customers over that time period. The accounting mechanism is the best vehicle for ensuring that the timing and purpose of the payments align with the customers making such payments, thus ensuring intergenerational equity.

The Commission acknowledges that the Company's auditors believe that such a regulatory asset may not be "probable of recovery" and may not be recorded on the Company's books for the purpose of GAAP accounting. However, pursuant to Commission Rule R8-27, GAAP accounting must reflect the Commission's ratemaking orders (taking into consideration certain conservative limitations); GAAP does not and should not dictate the Commission's regulatory authority. Further, based on the existence of long-lived regulatory assets reflected on the Company's Form 1 (as discussed by Public Staff witness Maness), it appears that there are times when at least the external auditors reviewing the FERC books and records have allowed long-term regulatory assets to be recorded.[23] There is no evidence that the Commission would abandon its long

[23] The Commission notes in this regard that the Company has proposed the establishment of a regulatory liability to return protected EDIT to customers, which is not expected to be resolved

precedent of recognizing and resolving regulatory assets, regardless of the length of time associated with the assets. Regulatory assets, whether established pursuant to a request by the Company, a stipulation, or as a result of a recommendation by the Public Staff, have been and will continue to be recognized and ultimately resolved by the Commission. The Commission would expect the Company's financial executives to explicitly point this out to the external auditors during the audit, and trusts that the external auditors would take the Commission's history and the language of this Order into full account in their determinations.

The Commission finds and concludes, therefore, that the Company's revenue requirement shall reflect a reduction of $29.1 million in nuclear decommissioning expense. Further, the Commission finds and concludes that it is reasonable and appropriate for the Company to establish a regulatory asset in the same amount of the nuclear decommissioning expense, with a return. This will not be the last time the Commission considers the level of the Company's NDTF and the regulatory asset established in this case. Should future studies in the Decommissioning Docket or future rate cases show that the level of the NDTF has materially changed, the Commission will take appropriate steps to ensure that adequate funds will be available to decommission the Company's nuclear units.

for 20 years. The Commission notes an inconsistency in the Company's logic whereby the Company contends it is appropriate for customers to wait twenty years to receive the flow back of a tax benefit, yet it is inappropriate for the Company to wait to receive decommissioning funds over an elongated time period through a regulatory asset.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 42-47

The evidence supporting these findings of fact and conclusions is contained in the testimony of Company witnesses Doss, Spanos, and Kopp, and the testimony of Public Staff witness McCullar.

Depreciation Rates

Company witness Doss introduced Doss Exhibit 3, the Depreciation Study which was prepared by Gannett Fleming Valuation and Rate Consultants, LLC. (T 12 p 51) As explained by witness Doss, the Depreciation Study included updates to estimates of final plant decommissioning costs for steam, hydraulic, and other production plants, as well as updated forecasted generation plant retirement dates. (Id.) In addition, witness Doss introduced Doss Exhibit 4, the Decommissioning Cost Estimate Study prepared by Burns and McDonnell, an external engineering firm. This report included estimates for final decommissioning costs at steam, hydraulic, and other production plants. (Id.)

As witness Doss explained, the depreciation rates for various fossil and hydro plants were also updated due to changes in the probable retirement dates. The probable retirement dates were updated primarily to align dates with current licenses, industry standards, or operational plans due to aging technology, assumptions for future environmental regulations, or new planned generation. (T 12 pp 51-52) The Depreciation Study also incorporates generation assets placed in service since the last study, as well as the W.S. Lee Combined Cycle

Plant, once it goes into service. (T 12 p 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.)

On the issue of depreciation, the Public Staff presented the testimony of Roxie McCullar, a consultant with the firm of William Dunkel and Associates. Ms. McCullar testified that based on December 31, 2016 investments, DEC was proposing an increase in its depreciation annual accrual of $81,480,296. (T 26 p 773) Based on Ms. 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. (T 26 p 775) The difference between the Company's and the Public Staff's proposed depreciation annual accrual results from four adjustments proposed by Ms. McCullar, and one recommended by Public Staff witness Michael C. Maness, as discussed below.

Contingency

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. (T 26 p 778) Ms. McCullar explained that including a 20% contingency factor puts the risk of possible future unknowns on current ratepayers. (Id.) She 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. (T 26 pp 778-79) Ms. McCullar testified that putting all the risk of "estimated future unknown unidentified costs" on current ratepayers was inappropriate and recommended a contingency of 0%. (T 26 p 780)

DEC witness Kopp disagreed with Ms. McCullar's proposal to remove contingency from the estimates of future net salvage, explaining that contingency protects customers by ensuring more accurate estimates of the costs of terminal net salvage to be incurred in the future. (T 10 p 108) He stated that while these costs could not be specifically identified, it was reasonable to expect them to be incurred. (Id.) Mr. Kopp explained that direct decommissioning costs were estimated based on performing known tasks under ideal conditions. (T 10 p 109) However, Mr. Kopp admitted that Burns & McDonnell did not obtain any firm quotes for DEC facilities, but used unit pricing or its experience. (T 10 p 137) According to Mr. 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. (T 10 pp 109-10)

Mr. Kopp maintained that inclusion of contingency costs was standard industry practice. (T 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. (T 10 pp 111-12) Mr. 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. (T 10 pp 111-12) Mr. 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. (T 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. (T 10 pp 113-14) Mr. Kopp noted that Burns and McDonnell had performed a decommissioning study for Duke Energy Progress, LLC, 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. (T 10 p 114)

Witness Kopp contended that Ms. McCullar did not take into account that the direct costs were based on known tasks occurring under ideal conditions. (T 10 pp 115-16) He 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. (T 10 p 116) As for Ms. McCullar's contention that the Company should not recover a contingency for costs that cannot be identified at this time, Mr. 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. (T 10 pp 117-18)

On cross examination, Mr. 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. (T 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. (T 10 pp 133-34) Mr. 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.) (T 10 pp 131-33)

In his testimony, Mr. Kopp claims that, "As 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." (T 10 pp 112-13, emphasis added) He also states that the "Company performed no subsurface investigations, asbestos inventories, or groundwater sampling to identify and define remediation requirements during this planning phase." (T 10 p 112, emphasis added) However, on cross examination, Mr. Kopp admitted that the Company did perform asbestos inventories. (T 10 p 136) But instead of relying on studies that had been performed, "Burns and McDonnell did not rely upon these historical studies . . . ." (Kopp/Spanos Public Staff Exhibit 4) (T 10 p 136)

The Commission agrees with DEC that inclusion of a contingency is often a standard industry practice. However, the Public Staff has raised a valid concern that the contingency here is set to cover potential unknown costs that may or may not occur, and it is not reasonable to require current ratepayers to bear all of the risk. The Commission notes that Arizona has denied the inclusion of a contingency factor in the future estimated terminal net salvage used in the calculation of depreciation rates. The Corporation Commission of the State of Oklahoma in Order 657877 adopted the Administrative Law Judge's recommended finding that it was inappropriate to ask ratepayers to pay for future costs that may not occur and that were not known and measurable within the meaning of 17 O.S. § 284. The recommendation noted that the request for a contingency failed to consider the potential for occurrences that could reduce estimated costs. (OK PUD 201500208 p 164 of the May 31, 2016 ALJ Initial Report adopted by Order No. 657877) (attached)

The potential that the Decommissioning Study presented in this case is likely to be inaccurate concerns the Commission. Mr. Kopp has 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.

The Commission notes Mr. Kopp's experience and expertise, yet it notes the contradictions that the estimates are insufficiently precise to calculate a more refined contingency amount, but are adequate to calculate depreciation rates. The Company appears to be having its cake and eating it too. Further, the Company's assumption is only that costs will be higher than estimated; it ignores the potential for the Company to complete the project at or under projections. Additionally, the Company fails to take into account the possibility that scrap prices may increase or that the production plant may be repurposed, or sold. The collection of a contingency for future unknown costs inappropriately puts all of the risk of future unknown, unidentified costs on the current ratepayers.

Further, Mr. Kopp's claim that a contingency is needed to account for the unknown of asbestos is not 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. (Kopp/Spanos Public Staff Exhibit 4). Identifying these costs should reduce the unknown of asbestos and thus reduce any contingency.

The Commission finds that the contingency proposed for net terminal salvage in this proceeding is based on estimates that lack sufficient basis, especially in regard to the potential for environmental contamination and the costs of environmental remediation. While the Commission appreciates the Company's concern for keeping the cost of the Decommissioning Study 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. Based on the foregoing, the Commission concludes that including a contingency that is calculated as 20% of these estimates lacks sufficient basis and that a 0% contingency should be used.

Inflation of Electric Production Plant Estimated Future Terminal Net Salvage Costs

The second adjustment recommended by Public Staff witness McCullar involves the Company's inflation of the estimated future terminal net salvage costs. Ms. McCullar explained 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. DEC proposes to collect these inflated amounts in today's more valuable dollars from ratepayers. (T 26 pp 780-81) Ms. 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. (T 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.) Ms. 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. (T 26 p 282)

Instead, the Public Staff proposed that the estimated terminal net salvage costs be inflated to year-2023 dollars or the retirement date, whichever occurs first. (T 26 p 783) Ms. McCullar explained that the Company had indicated in discovery that five years is consistent with the period of time between rate cases (*See* Exhibit RMM-5), and thus by 2023, depreciation rates would be reviewed in a new base rate case. (T 26 p 784) During the evidentiary hearing, the Public Staff presented a slide from Duke Energy Corporation's fourth quarter 2017 earnings call that showed that DEC was planning for multiple rate cases between 2019 and 2023. (Spanos/Kopp Public Staff Cross Exhibit 2). Ms. 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. (T 26 p 784)

Company witness Spanos argued that as net salvage must be based on future costs, its decommissioning costs should also be based on an estimate of the costs at the time of decommissioning, and thus escalated to the time at which the costs are expected to be incurred. (T 10 p 85) He contended that the Public Staff's proposal to escalate net salvage costs to 2023 dollars would be insufficient to recover the Company's costs. (T 10 p 86) Mr. Spanos presented a hypothetical example to support his position. (T 10 pp 86-87) However, while Mr. Spanos indicated on cross examination that year one was the first year that the hypothetical plant went into service (T 10 p 141), the Company indicated in a discovery response that the hypothetical was not based on the assumption that the decommissioning costs were deflated to the first year the plant went into service. (*See* Kopp/Spanos Public Staff Cross Exhibit 5). Mr. Spanos also cited several authoritative depreciation texts to support his contention that net salvage should be recognized as a future cost. (T 1 pp 88-90)

The Commission agrees with Ms. McCullar that charging current ratepayers depreciation expense on the basis of estimated terminal net salvage costs calculated in year 2048 dollars places too high a burden of future inflation on those ratepayers. Due to inflation, the dollars in the future retirement years will have a lower purchasing power than the year-2018 dollars that will be collected from the current ratepayers.[24]

It also appears that the hypothetical Mr. Spanos uses to support his claim that terminal net salvage "must be escalated" is not consistent with the Public Staff's proposal, but is rather a strawman hypothetical. Mr. Spanos' hypothetical seems to deflate the decommissioning costs to the year placed in service, while Ms. McCullar's proposal inflates the estimated terminal net salvage costs to the year 2023. Ms. McCullar proposes to use the decommissioning costs, less the contingency, as estimated in the Decommissioning Study. She did not propose to estimate the decommissioning costs to the dollar value of the first year the production plant went into service, which appears to be the assumption in Mr. Spanos' hypothetical. Thus, the Spanos hypothetical is not representative of the Public Staff's proposal.

In his testimony, DEC witness Spanos cites certain authoritative depreciation texts regarding net salvage, including Wolf and Fitch's Depreciation

[24] For example, assume a savings bond worth $106,000 matures in 32 years. Assuming a 2.5% interest rate, that savings bond has a present market value of $48,000. No reasonable investor would pay $106,000 using today's dollars for a savings bond that would return $106,000 in 32 years.

Systems (Wolf and Fitch's) and NARUC's Public Utilities Depreciation Practices. The Commission notes that those same texts also discuss the importance of the net salvage factor in the setting of the depreciation rate and the impact of inflation. For instance, Wolf and Fitch's points out that the depreciation rate is more sensitive to the net salvage estimate than to the life estimate, stating:

> It is not unusual for a mass property account of a utility to exhibit large negative salvage. In such cases, the depreciation accrual rate may be more sensitive to the salvage estimate than to the life estimate.[25]

Wolf and Fitch's also notes that using a net salvage ratio that includes inflated future dollars in the numerator and historic dollars in the denominator is a ratio using different units, stating:

> One inherent characteristic of the salvage ratio is that the numerator and denominator are measured in different units; the numerator is measured in dollars at the time of retirement, while the denominator is measured in dollars at the time of installation. Inflation is an economic fact of life and although both numerator and denominator are measured in dollars, the timing of the cash flows reflects different price levels.[26]

Additionally, NARUC's Public Utilities Depreciation Practices states:

> The sensitivity of salvage and cost of retirement to the age of the property retired is also troublesome. Due to inflation and other factors, there is a tendency for costs of retirement, typically labor, to increase more rapidly than material prices.[27]

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[25] Wolf and Fitch's p 267. (attached)

[26] Id. at p 53. (attached)

[27] NARUC's Public Utilities Depreciation Practices (1996) p 19. (attached)

NARUC's Public Utilities Depreciation Practices concludes that "[c]ost of retirement, however, must be given careful thought and attention, since for certain types of plant, it can be the most critical component of the depreciation rate.[28]

Other jurisdictions have denied the escalation of demolition costs in the future estimated terminal net salvage used in the calculation of the depreciation rates. The Corporation Commission of the State of Oklahoma in Order 657877 adopted the ALJ recommendation that:

> the Commission should deny the proposed escalation of demolition costs in this case because (1) the escalated costs do not appear to be calculated in the same manner as other calculations; (2) the Company did not offer any testimony in support of the escalation factor; (3) an escalation factor that does not consider any improvements in technology or economic efficiencies likely overstates future costs; (4) it is inappropriate to apply an escalation factor to demolition costs that are likely overstated; (5) asking ratepayers to pay for future costs that may not occur, are not known and measurable changes within the meaning of 17 O.S. § 284; and (6) the Commission has not approved escalated demolition costs in previous cases.

(OK PUD 201500208 p 164 of the May 31, 2016 ALJ Initial Report adopted by Order No. 657877). (attached)

In January 2018, the Corporation Commission of the State of Oklahoma reaffirmed this decision finding the Attorney General's total demolition cost estimates to be reasonable and appropriate and rejecting escalated cost estimates of production plant demolition costs as proposed by Mr. Spanos. (OK Cause No.

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[28] Id.

PUD 201700151 paragraph 107 of the ALJ Report adopted in Order No. 672864) (attached). Recently, the Arizona Corporation Commission accepted a Settlement in which the dismantlement costs were set to "current dollars" in the calculation of the depreciation rates. (AZ Docket No. E-01933A-15-0239 p 10 of Decision No. 75975, also see p 9, lines 6-12 of the July 25, 2016 TEP Rebuttal Testimony of David J. Lewis) (attached)

Additionally, other jurisdictions have recognized that collecting future inflated estimated costs from current ratepayers in today's more valuable dollars is inappropriate. The Public Service Commission of the District of Columbia in Order No. 15710 stated: "Fairness and equity require that the Commission adopt a methodology that, to the extent possible, balances the interest of current and future ratepayers." It continued: "Pepco should not be allowed to charge current customers for future inflation, nor should Pepco be allowed to charge current customers in higher-value current dollars for a future cost of removal amount that is calculated in lower-value future dollars." (FC 1076 paragraph 252 of Order No. 15710). (attached) Further, the Public Service Commission of Maryland in Order No. 51817 stated:

> The Commission has carefully reviewed the record and finds that the Present Value Method should be adopted for the recovery of removal costs. The Straight Line Method recovers the same annual cost in nominal dollars from ratepayers today as it does at the time plant is removed from service. However, a dollar is worth substantially more today than it will be 20 to 40 years from now. Consequently, today's ratepayers would pay more in "real" dollars under the Straight Line Method for the recovery costs of the plant they consume than would future ratepayers when net salvage is negative, as everyone projects.
>
> (Case No. 9092 p 30 of Order No. 81517). (attached)

The Commission finds that the proposal of the Public Staff to inflate the estimated terminal net salvage costs to the year 2023 has merit. The proposal is equitable, as it protects ratepayers from bearing all the risk of unknown future inflation for up to 30 years, while it also protects the Company by allowing it to collect net salvage in 2023 dollars, by which time depreciation rates should have been reassessed in a future base rate case. Further, the proposal is based on sound accounting principles and is similar to positions advocated by parties and adopted by commissions in other jurisdictions.

Other Production Interim Net Salvage

The third adjustment proposed by Public Staff witness McCullar was to the interim net salvage percentages of negative 5% proposed by DEC for Other Production Accounts 342, 343, 344, 345, and 346. (T 26 p 786) Ms. McCullar pointed out that the historical analyses for these accounts show that, on average, the net salvage 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.[29] (Id.) She 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. (Id.) Therefore, Ms. McCullar proposed a 0% interim net salvage based on DEC's actual experience.

[29] Doss Exhibit 3 (2016 Depreciation Study) pages 319-324, attached as Exhibit RMM-6. DEC response to Public Staff Data Request 9-12, Attachment 2 indicates that the net salvage costs related to final retirements have been excluded from the historical net salvage data shown on pages 319-324 of Doss Exhibit 3.

(Id.) She noted that the 0% interim net salvage would not include the final decommissioning costs. (Id.) 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.

DEC witness Spanos testified that he recommended an interim net salvage percent of negative 4% for Other Production accounts. (T 10 p 90) 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.) Mr. 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 noted 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.) Mr. Spanos also stated that the high gross salvage numbers were related to the rotable parts of combined cycle facilities, consistent with Duke Energy Progress, LLC. (Id.)

In regard to Mr. Spanos' contention that 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, Mr. 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. (T 10 p 143)

The Commission finds that the Public Staff's proposal to set an interim net salvage percentage of zero 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.

<u>AMI Meter Average Service Life</u>

The Public Staff's fourth recommended change to the Company's depreciation rates was to adjust DEC's proposed 15-year average service life of its Advanced Metering Infrastructure (AMI) meters to 17 years. Ms. McCullar testified that the Company indicated that the manufacturer of the AMI meters estimated that they would have an average life of 15 to 20 years. (T 26 p 787) (*See* Exhibit RMM-7) While DEC proposed to use the shortest life within that range, thereby increasing the potential depreciation expense for these meters, Ms. McCullar recommended that a life of 17 years be used, especially in light of DEC's limited experience with AMI meters. (<u>Id</u>.) She explained that 17 years was in the middle of the range, and was reasonable and fair to both the Company and ratepayers. (Id.) The impact of this single adjustment is a decrease in DEC's proposed depreciation rates as of December 31, 2016, of $1,656,335, as shown on p 15 of Exhibit RMM-1 under Account 370.02.

DEC witness Schneider testified on rebuttal that the trend across the industry was shorter depreciation schedules, as AMI systems are more computer-based. (T 18 pp 338-39) He noted that commissions in Kentucky, Ohio, and Florida use 15-year depreciation lives for the AMI meters of DEC's affiliates in those states. (T 18 p 339) DEC witness Spanos also supported a 15-year average life based on the type of asset, trends for new meters, technological advancement, the use of computers and sensors in the meters, and the expected life of primary AMI meter components. (T 10 p 93) However, he agreed with Ms. McCullar that the manufacturers' estimates of 15-20 years are based on the expected physical life of the AMI meters. (T 10 pp 92-93) He also contended that Ms. McCullar had not considered the potential for obsolescence. (T 10 p 92) However, Mr. Spanos agreed that another consideration when contemplating a full-scale replacement of meters should be a cost-benefit analysis. (T 10 p 156)

The Commission finds that it is reasonable to use an average service life of 17 years for the new AMI meters, which is even below the middle of the manufacturers' range. While DEC has pointed out certain technological characteristics of AMI meters, it has not shown that the manufacturers' estimates were high, inaccurate, or unreliable. DEC may want to participate in another full-scale replacement of meters in 15 years, but such a rationale does not merit using a shorter service life and thereby charging customers higher depreciation rates for the new AMI meters. As such, the Public Staff's proposal is appropriate for this new technology and more than reasonable. The Commission further notes that it recently approved the use of a 17-year life for AMI meters for Duke Energy Progress, LLC, in Docket No. E-2, Sub 1142.

Remaining Useful Life of Meters Replaced by Expedited Installation of AMI Meters

DEC witness McManeus testified on direct that the Company seeks to establish a regulatory asset for meters being replaced under the Company's AMI deployment. (T 6 pp 254-55) She noted that the depreciation study provides for recovery of the remaining net book value of the replaced meters over three years. (T 6 p 255)

Public Staff witness Maness testified that he did not oppose the establishment of a regulatory asset, but disagreed with the Company's proposal to recover all costs of the replaced meters over three years. (T 22 pp 103-04) He noted that the Company had indicated that these meters to be replaced have an average estimated remaining useful life of 15.4 years (*see* Exhibit RMM-8), and thus he recommended that the replaced meters be depreciated over the same period. (T 22 p 104) Mr. Maness found no reason to accelerate the recovery of the remaining cost of the meters. (Id.) The impact of this single adjustment is a decrease in DEC's proposed depreciation rates as of December 31, 2016, of $45,732,237, as shown on p 15 of Exhibit RMM-1 under Account 370.01.

Company witness Spanos proposed that the unrecovered costs of the meters be recovered over their remaining service lives of 2.8 years. (T 10 p 93) He disputed Mr. Maness' contention that the remaining life of the meters was 15.4 years on the basis that the number was correct if the meters were not being replaced. (T 10 pp 93-94) Mr. Spanos contended the Public Staff's proposal was not equitable as future customers would be paying legacy meter costs even after many of the new AMI meters had been retired. (T 10 p 94)

In this proceeding, the Commission is being asked to approve the recovery of costs of new AMI meters, at a significant additional cost to customers, as well as acceleration of the recovery of the costs of the meters that the AMI meters will replace, again at a significant cost. Lengthening the term of the recovery of the unrecovered costs of the replaced meters can place legacy costs on future customers, but it also can reduce the burden on current customers.[30] Furthermore, there is no logical ratemaking rationale that would dictate that the cost of the legacy meters must be recovered over their shortened service life, when that shortened life is simply the result of a Company decision to accelerate their removal. Weighing these considerations, and in light of the other issues decided in this case, the Commission concludes there is no justification to accelerate recovery for the remaining costs of the replaced meters. Had the meters not been replaced, the

[30] While the Company's raising of the issue of intergenerational equity is a legitimate consideration, the Commission notes that the Company's tax proposal would flow back taxes collected from past and current customers over the next 20 years, also raising intergenerational equity issues that the Company conveniently ignores.

Company would have maintained its otherwise existing cash flow as the costs were recovered over a 15.4 year period. Under the Public Staff's proposal, the Company is still assured of recovering its investment, albeit not as quickly as the Company prefers. The Company should not reap an accelerated cash flow benefit from the early retirement and replacement of used and useful property, thus increasing the burden on current ratepayers disproportionately, regardless of the merit (or lack thereof) behind the replacement. Allowing accelerated recovery in this case would create a perverse incentive for the Company to pursue similar replacements in an effort to boost rate base and cash flows, which would only result in higher rates for customers. The Commission finds that it is just and reasonable for the remaining costs of the replaced meters to be recovered over 15.4 years, the remaining life of the meters had they not been replaced.

CIGFUR Depreciation Recommendation

CIGFUR witness Phillips recommended that that customers not be burdened at this time by the impact of shortening service lives of generating assets based upon assumptions about changing and evolving environmental regulations. (T 26 p 273) He also recommended that any approved changes to depreciation rates net to a zero-dollar impact on the level of depreciation expense included in rates. (Id.)

Witness Spanos asserted that witness Phillips provided no support or justification for his net zero proposal other than a desire that depreciation rates not increase. (T 10 p 94) Mr. Spanos asserted that current depreciation rates are insufficient and should be increased. (T 10 p 95) He also disputed Mr. Phillips' contention that depreciation rates have changed due to changes to life spans as a result of environmental regulation; he contended that there are a variety of reasons that depreciation rates change over time as evidenced by the Depreciation Study filed in this case. (Id.) Mr. Spanos noted that the Depreciation Study includes all of the Company's assets, and that changes in depreciation rates occur for many reasons, including updated historical data, updated service life and net salvage estimates, and additions to generating facilities. (Id.) He noted that the current depreciation study is based on the available information regarding the Company's assets, and the depreciation rates therefore need to be updated to reflect current circumstances. (Id.)

The Commission finds that Mr. Phillips' blanket recommendation regarding depreciation rates lacks support and therefore should be rejected.

Conclusions on Depreciation

Based on the foregoing conclusions regarding use of a 0% contingency for future "unknowns" in the estimate of future terminal net salvage costs, inflation of the estimated terminal net salvage costs to the year 2023, use of an interim net salvage percentage of zero for Accounts 342, 343, 344, 345, and 346, use of an average service life of 17 years for the new AMI meters, and use of a 15.4 period of recovery for the remaining costs of the meters replaced due to the expedited deployment of AMI meters, the Commission finds it is reasonable and appropriate to approve the use of the Public Staff's proposed depreciation rates as shown on Exhibit RMM-1.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 48-49

The evidence supporting these findings of fact and conclusions is found in the testimony of Company witnesses Fountain, McManeus and Simpson, Public Staff witnesses Williamson and Maness, NCSEA witness Golin, Tech Customers witness Strunk, CUCA witness O'Donnell, and the entire record in this proceeding.

<u>Power Forward programs are not unique and extraordinary</u>

Witness Simpson testified that the Power Forward Initiative is a collection of programs that includes projects to upgrade the Company's transmission and distribution (T&D) grid. Witness Simpson testified that Power Forward is necessary because of more frequent weather events, aging components, and the addition of distributed energy resources (DER). While weather is something the Company has always dealt with in maintaining electric service, Simpson stated that more frequent severe weather events drive worsening reliability metrics and believes that enhanced hardening of the grid will improve the overall reliability of the grid. (T 17 p 118) However, Simpson conceded that weather only caused 1.8 percent of the outages in the 2016 test year, which equated to only 3.3 percent of customer outage minutes, while vegetation management related outages accounted for 20.88 percent of outages, equating to 31.7 percent of the customer outage minutes in the test year. (T 23 pp 252-53) Even with more frequent extreme weather events, Simpson admitted that the distribution of root cause for outages will remain the same in terms of the number and types of events: 20 percent for vegetation management related outages, close to 20 percent for equipment failure, and six to ten percent for public accidents, with only the minutes per interruption increasing. (T 24 p 23)

As to the wear and tear on and age of equipment, 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. (T 23 p 215) Although not a new revelation to the Company, 30 percent of the Company's T&D assets will be beyond their useful life in the next ten years; therefore, not even the best maintenance can stop the cumulative effects of age on the system. (T 17 p 15; T 23 p 215) Simpson acknowledged that that the grid has evolved over decades. (T 17 pp 137-38) He also stated that the grid is more hardened today in terms of quality of design than it used to be. (T 17 pp 121-22)

DEC plans to spend $7.7 billion over Power Forward's ten year plan, including $2.9 billion in capital and $130 million in operations and maintenance (O&M) expense in the first five years. (T 17 p 16) Witness Simpson testified that Power Forward includes the following seven programs: (1) Targeted Undergrounding; (2) Distribution Hardening and Resiliency; (3) Transmission Improvements; (4) Self-Optimizing Grid; (5) Advanced Metering Infrastructure (AMI) (which Simpson stated on rebuttal would not be recovered through DEC's proposed Grid Rider); (6) Communications Network Upgrades; and (7) Advanced

Enterprise Systems. According to witness Simpson, these programs will primarily focus on projects that: 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 generation; and address physical and cyber security, worsening weather, customer disruption, and wear and tear on equipment. (T 16 pp 108, 150-54)

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. (T 16 p 25) Simpson agreed in his rebuttal 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 Targeted Undergrounding program is unique because of the data analytics that the Company employs to determine which individual line segments (versus entire circuits) to underground. (T 16, pp 162-63) Witness Simpson stated that the Company is not talking about a massive undergrounding project but rather targeting specific poor performing line segments to be undergrounded, which now can be determined in minutes and hours as a result of new analytic capabilities, versus the days and weeks it took in the past. (T 16 pp 162-63) However, Simpson conceded 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. (T 17 p 72)

In developing its Targeted Undergrounding program, the Company did not account for the time and cost of repairing an underground line outage, which historically is considerably greater than routine repairs of overhead lines. (T 17 pp 108-09) Further, witness Simpson did not know the details regarding the ongoing status of other non-electric utility lines on poles after DEC has undergrounded its lines. He stated that several options would be available for these non-electric utility lines, and it would ultimately depend on the joint use agreement signed with the specific non-electric utility company as well as the site specific details of each project. (T 17, pp 98-99 and DEC late filed exhibit regarding Power Forward dated 4/2/18, p 2) Witness Simpson admitted that the Company had not performed any undergrounding of distribution lines in response to the Public Staff's recommendation, provided in the 2003 Undergrounding Report, to underground the 10 most troubling circuits on the utility's system each year. (T 23 p 256; T 24 p 14)

According to witness Simpson, the Distribution Hardening and Resiliency program includes retrofitting transformers to eliminate common outage causes, replacing aged and/or deteriorating cable and conductors, and providing back feed capability to vulnerable communities. (T 16 pp 110) 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. (T 16 pp 160-61) Simpson stated that these categories only account for ten percent of Power Forward and also claimed that they are the only overlap between the Company's customary spend and Power Forward. (T 16 pp 160-61; T 17 p 140) The reason those categories of projects are contained in both the customary spend and Power Forward is because the Company wants to expedite resolution of common causes of outages. (T 16 pp 165-66) 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. (T 23 p 22)

Another category of projects within the Distribution Hardening and Resiliency program is called "Areas of Vulnerability," which identifies small and medium-size towns and individual customers that need back feed lines due to the possibility of long duration outages. The budget for this program alone for DEC is $75 million. During the hearing, witness Simpson identified the Charlotte Douglas Airport and the Greensboro Coliseum and geographic regions such as Lake Lure as included in the areas of vulnerability. (T 18 p 223) Simpson stated that customers like the Greensboro Coliseum could receive and pay for more back feed ties through normal rate tariffs, if requested by individual customers, but he is more concerned with geographic needs. (T 18 p 224) This program could require the acquisition of new right-of-ways for distribution lines to feed small towns, which has been factored into the planning. (T 18 p 226) More significantly, when asked by Commissioner Brown-Bland to provide a list of the sites that are included in the "Areas of Vulnerability" as a late-filed exhibit, the Company acknowledged that the 15 "number of units" listed in the Simpson Rebuttal Exhibit 2 is not reflective of actual projects deemed "Areas of Vulnerability" projects that the Company plans to execute. Rather, the 15 "number of units" in the referenced chart was derived by taking the then-applicable project budget of $75 million and dividing it by a rough order of magnitude average expected project cost of $5 million, which yields 15 project units. Accordingly, the Company could not file a list of what these 15 project units are or why they meet Area of Vulnerability criteria because the 15 project units in the referenced chart are not actual projects but instead are indicative financial planning placeholders that were used at the time Simpson Rebuttal Exhibit 2 was created. (April 23, 2018 Company response to Commission's April 19, 2018 Order Requiring Filing of Late-Filed Exhibit)

Witness Simpson explained that the Transmission Improvements program includes projects that will update and replace transmission system equipment that is likely to fail in the near future and add systems that will notify the Company of problems before they result in an outage. (T 16 p 115) The program will also include pole replacement, line rebuilds, substation animal mitigation, and other unspecified physical and cyber security improvements. (Simpson Rebuttal Exhibit 2 p 24) Witness Simpson stated that this program does expedite replacement of obsolete and old design equipment, replacing them with newer equipment that will allow for improved proactive monitoring of the transmission system, in part due to the national security threats the transmission grid must guard against. (T 17 p 65)

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 in enough of the most current technology to provide a system wide picture. (T 17 p 133) Substation upgrades will account for the state-of-the-art equipment already installed to determine which substations need upgrades to reach the Company's desired level of functionality. (T 17 p 134) Another category of projects addressing substations is animal mitigation. Simpson conceded that the Company has historically addressed animal mitigation but contended many substations still need these upgrades due to national security issues. (T 17 pp 66-67)

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. (T 16 pp 112-13, 141; T 17 pp 151-52) Witness Simpson asserted that this effort will also make the grid "stiffer," allowing for more DER to be connected. (T 17 pp 151-52) Mr. Simpson acknowledged, however, that adding redundant lines for back-feed or tie-ins is something that the Company has previously done around some urban areas. (T 23 pp 246-47)

Witness Simpson stated that the Enterprise Systems and Communication Network Upgrade programs will help integrate the control and analytics systems with the data monitoring and control devices in the field. (T 16 p 116) This program includes upgrades to the existing Outage Management System, Distribution

Management System, Volt/VAR Management System, Supervisory Control and Data Acquisition system, and other systems, thus enabling more advanced analytics and control of the distribution grid. (T 16 p 118)

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, not by the Commission, but by the Company based on projections of the costs necessary to maintain a reliable grid. (T 16 p 106; T 17 p 58) Witness Simpson stated that the Company has spent approximately $2.6 billion over the last four years on "customary" capital expenditures for its T&D infrastructure. Of the $2.6 billion, $770 million was invested into the transmission system and $1.8 billion into the distribution system. (T 16 p 92) Simpson broke down the transmission capital expenditures as follows: 36 percent on Business Expansion/Capacity, which was to serve load and meet the North American Reliability Council (NERC) Planning Standards; 12 percent of investment, driven by generation projects, including new generator interconnections and decommissioning of obsolete equipment; six percent was driven by compliance projects, cyber security and physical security programs defined in NERC and Critical Infrastructure Protection (CIP) Standards; and 46 percent due to reliability improvement and maintenance programs, such as replacement of wood poles, obsolete substations, and line equipment. (T 16 pp 92-94) Witness Simpson itemized the Company's "customary" distribution capital expenditures over the last four years as follows: 55 percent for expansion-related work, including serving new customers, lighting installations, and additional capacity; 22 percent for infrastructure maintenance activities such as pole replacement and underground cable replacement; 23 percent 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 teams that apply state-of-the-art technology to automatically isolate the cause of an outage and restore service to customers. (T 16 pp 94-95)

Witness Simpson testified that the Company needs to continue its "customary" investments in the T&D system to maintain the grid and add new customers, for which DEC originally budgeted to spend $4.5 billion from 2017-2021. Witness Simpson indicated that the money allocated to Power Forward would be in addition to the customary amount. (T 16 p 106) On rebuttal, 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 after Power Forward was announced. (T 16 pp164-165; T 23 p 179) Therefore, there is now a projected customary spend of $3.4 billion, along with another approximately $3.03 billion of projected costs in Power Forward, comprised of $2.9 billion in capital and $130 million for O&M, all to be spent between 2017 and 2021. (T 16 pp 106, 191) 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 been recovered yet, it was moved into the Power Forward account to be recovered through the Grid Rider. (T 23 p 261)

Tech Customers witness Strunk testified that DEC has not provided sufficient justification to treat grid modernization investments differently from the other infrastructure investments that comprise DEC's rate base and that DEC's attribution of costs into the grid modernization category is seemingly arbitrary. (T 26 p 465)

NCSEA witness Golin testified that with respect to the Power Forward investments, the Company has not made clear why some investments fall under normal rate recovery and other investments fall under the Grid Rider. She asserted that the Company has only stated that it will assign a separate "routine and [Grid] Rider installation by aligning the scope and work plans associated with each to distinct accounting code block that captures these costs separately, where practical." She testified that the Company has also failed to delineate a clear decision-making procedure for how it determined which capital investments are routine and which investments fulfill the goals of the Power Forward proposal. She stated that this is evident by the fact that, before the Power Forward proposal was made, the estimated customary spend on T&D was $4.5 billion. After the Power

Forward proposal was made, the Company transferred $1 billion dollars of proposed customary spend and redirected it to the Power Forward proposal and the proposed cost recovery through the Grid Rider. (T14 p 28)

Public Staff witness Williamson testified that the Public Staff does not support the establishment of the Grid Rider because the Public Staff is not persuaded that all the components of Power Forward will result in modernization of the grid versus meeting DEC's everyday regulatory responsibility 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, which should always be part of DEC's everyday planning and operations. Williamson described the Company's proposal as incredibly wide in scope with many disparate parts and elements. (T 22 p 172) Witness Williamson stated that if the Commission decided to approve a rider for Power Forward, the Targeted Undergrounding program costs should not be recovered through the rider because 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 AMI installation program predates the first mention of Power Forward and already has approximately 750,000 meters installed and therefore should not be recovered in the Grid Rider. (T 22 pp 40-41)

Public Staff witness Maness agreed with witness Williamson that the Public Staff is not persuaded that all of the Power Forward components will result in grid modernization as opposed to normal improvements that DEC should continuously undertake. Thus, the Grid Rider should not be approved. Witness Maness testified that riders not specifically established by statute, similar to deferral accounting, are an exception to the general method by which rates are normally set for North Carolina's electric public utilities. Witness Maness stated that it is important that items set aside for special treatment, such as riders and deferred costs, should be both extraordinary in magnitude and very unique in type. While it is certainly true that DEC intends to expend significant funds in pursuit of Power Forward, the Public Staff believes that many of the Power Forward programs are the types of activities that the Company undertakes on a routine and continuous basis, with or without the prospect of modernization. As such, these items are neither extraordinary nor unique, therefore Power Forward is not sufficiently tailored to warrant a rider for expedited cost recovery. Witness Maness further testified that when a rider or deferral accounting is established, costs intended to be included in the rider should be easily identifiable. He explained that many Power Forward projects are vaguely defined as evidenced by the general confusion when witnesses attempted to discuss the projects actually contained in Power Forward. (T 22 pp 88-93)

The Commission finds and concludes that the reasons DEC says underlie the need for Power Forward are not unique and extraordinary to DEC. 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. While the Company suggests that these issues have created a new era of grid operations, the Commission determines that management of these issues will be routine and customary for the foreseeable future.

The Commission recognizes that the data provided by DEC shows an increase in convective weather events in the last eight years; however, the Commission notes that weather has always been a major aspect of any utility's planning and operations since the beginning of electric utility service. Indeed, North Carolina has a history of weather variability, including severe weather events impacting electric utility service in which weather trends have worsened and then eased for a period of time. Further, in DEC's own outage root cause analysis, weather was only shown to cause 1.8 percent of all outages in the test year, equating to only 3.3 percent of customer outage minutes.

As discussed elsewhere in this Order, the Commission finds that the vegetation management program agreed to in the Stipulation should alleviate some of DEC's reliability issues. The Commission finds that the Company did not account for the impact of a properly executed vegetation management plan on the reliability issues the Company predicts in the absence of Power Forward.

The Commission also finds and concludes that managing Company T&D assets, and maintaining and replacing aging equipment has been, and should continue to be, part of the Company's normal course of operations. It is within the

Company's statutory obligation as the exclusive franchisee in its service territory to provide adequate and reliable electric service to its customers. Monitoring, maintaining, and replacing equipment with like or new components is part of the Company's everyday obligation to provide electric service.

Witness Simpson states that over 30 percent of the Company's T&D assets will be beyond their useful life in the next ten years. As service quality has been generally adequate in the past, the Commission does not find that the Company has been negligent in its management of these assets to this point. However, the Commission finds that it is the Company's responsibility to determine when assets become unreliable and are in danger of disrupting service, and should take appropriate actions to ensure that its system does not reach a point that the Company is unable to provide adequate and reliable service. This should be part of the Company's normal course of business. Further, if the Company determines that many of its grid assets can no longer be maintained and therefore need replacement, it makes logical sense to the Commission that DEC would (as it has been) update and replace such assets with equipment that the Company believes will be necessary to continue to provide adequate and reliable service in the future.

The Commission finds and concludes that projects comprising Power Forward are projects that are a routine and customary part of DEC's duty to ensure adequate and reliable service to the citizens of North Carolina. The costs of the Company's Targeted Undergrounding program comprise almost 40 percent of Power Forward, but it is not a program that significantly changes the business of utility service and merely utilizes a technique that has been used for decades by all public utilities, including DEC. Witness Simpson stated in his direct testimony that DEC has approximately 37,100 miles of underground distribution lines, making up over 35 percent of the distribution grid. While the Commission acknowledges that many of these undergrounded lines were installed as new customer connects, undergrounding overhead lines to improve reliability and enhance SAIFI and SAIDI metrics is not a new concept.

In 2003, the Public Staff prepared a report researching the feasibility of undergrounding the State's entire distribution grid for the North Carolina Natural Disaster Preparedness Task Force. The report found that undergrounding the entire distribution grid was too costly, but did provide recommendations for the utilities to consider going forward. The Public Staff's report concluded that the best course of action in light of the results of the study was for each utility to: (1) identify the overhead facilities in each region it serves that repeatedly experience reliability problems based on measures such as number of outages or number of customer-hours out of service, (2) determine whether conversion to underground is a cost-effective option for improving the reliability of those facilities, and, if so, (3) develop a plan for converting those facilities to underground in an orderly and efficient manner, taking into account the outage histories and impact on service reliability. The report stated that such a plan might include a policy similar to that of Dominion Virginia Power of annually identifying the "worst 10 circuits" and "worst 10 devices" in each of its regions and taking appropriate steps to improve or replace each of these circuits and devices. Simpson Rebuttal – Public Staff Cross Examination Exhibit 3, p 41 (T 24 exhibits part 1 p 161)

Witness Simpson testified that DEC has not conducted any undergrounding of troubled circuits or devices in response to the Public Staff's 2003 report over the 15 years since it was published. Witness Simpson attempted to distinguish DEC's current undergrounding program from Dominion's program cited in the Public Staff's report, stating that DEC's program uses new advanced data analytics to determine not only the circuit that causes disruptions, but also individual line segments of the circuit. The Commission recognizes the difference in the programs, but finds that had DEC implemented the program recommended by the Public Staff over the last decade and a half, the Company likely would have addressed many of the problem circuits identified in the current program. The Company should not be rewarded for failing to implement the program by receiving expedited cost recovery through the form of a rider. Further, the Commission concludes that the new data analytic tools that DEC is using to identify the line segments in the Targeted Undergrounding program do not make the program itself an extraordinary or unique modernization project. As stated earlier, undergrounding is not a new concept and the industry has possessed the capability to determine which circuits and devices have caused the most problems for at least 15 years, as evidenced by Dominion's program. Data analytics, as witness Simpson admitted, is neither a new phenomenon, as it has been used by utilities for decades, nor is this current iteration of data analytics likely to remain unchanged for the foreseeable future. Companies are perpetually developing new methods and models to dissect and evaluate data in determining the best and most efficient way to operate all facets of their business. If every time the Company developed a new data analytic model it was allowed to request a modernization rider, there would be no end to such riders.

Conversely, if the Commission considers every new data analytic model a modernization of its operations, then the Company is in a perpetual state of modernization, making modernization part of its routine and ordinary business. One example is AMI infrastructure. Once AMI is fully operational, the Company will have thousands of new data points on a more granular level than ever before. The Commission encourages DEC to use that data to refine its service, but does not believe that any new analytical models created from such data will be unusual or extraordinary. Thus, data analytics alone cannot make the Targeted Undergrounding program unique enough to warrant an annual rider. The Commission also finds that while the Company incorporated all of the benefits of undergrounded lines, such as fewer outages and less service repairs, the Company, in determining which lines to underground, did not include the longer outage times and more costly repairs when undergrounding lines experience outages. The Commission concludes that the Targeted Undergrounding program can provide a reduction in SAIFI and SAIDI metrics but that clearing the backlog of vegetation management miles and adhering to the 5/7/9 plan that the Company has developed, and which it has agreed to do pursuant to the Stipulation, will be a more cost effective option in many areas identified for undergrounding. Additionally, many of the areas identified for targeted undergrounding are in heavily vegetated residential neighborhoods, and as witness Simpson admitted, ten percent of these projects are also part of the current vegetation management backlog.

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 business of operating and maintaining its distribution grid. This program contains projects totaling $1.94 billion of Power Forward's approximately $7.7 billion DEC total. 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. Witness Simpson testified that these projects make up about ten percent of the total budget of Power Forward statewide. Analogous to their overall Power Forward costs, those projects make up approximately ten percent of DEC's portion of Power Forward or $793.5 million of DEC's $7.7 billion. The Commission finds that these project categories are clearly within the Company's normal course of business and are not unique nor appropriate to be included in a rider.

Of the remaining $1.146 billion proposed for Distribution Hardening and Resiliency, many of the categories are described as replacements, retrofits, or improvements. In fact, when looking at the Distribution Hardening and Resiliency program as a whole, only $823 million of the total $1.94 billion is allocated to projects that are not explicitly for rebuilds, replacements, retrofits, or improvements, showing that these projects, totaling approximately $1.13 billion are all needed to replace or enhance existing assets on the distribution grid. As stated above, the Commission's position is that determining which assets need to be repaired, retrofitted or replaced is part of the Company's ordinary course of business, as it is obligated to continuously provide adequate and reliable service. Of the remaining $823 million in the program, $14.4 million is for Hazard Tree removal, which is also part of the Company's vegetation management program and therefore customary. The Company has budgeted $500 million for Feeder Ties to lessen long duration outages, which should be a normal and customary goal for the Company when providing reliable service on a system wide basis. Further, witness Simpson admitted that the Company currently maintains such feeder ties in more urban areas; therefore, the Commission finds these projects to be customary. Another $210 million for "capacity," appears to be for either upgrading or building new substations that make the grid more "stiff", or to allow for new customer load additions, either of which would be part of the Company's normal course of business and could be part of its customary spend to accommodate new load. The Company designated $20 million for "sectionalization", which witness Simpson testified is part of the 23 percent of the Company's customary spend that is for reliability improvements. In addition, the Company budgeted $3.4 million for electronic reclosers that have been installed in many places throughout the distribution grid in the past.

The Commission has also reviewed the $75 million designated for "Areas of Vulnerability". First, the Company has not identified these "areas of vulnerability." According to a late-filed exhibit requested by the Commission on April 23, 2016, the Company merely took a total budget number and divided it by an average expected project cost to arrive at the number of projects. In addition, because there are no specific projects, the Company cannot identify why the 15 projects meet areas of vulnerability criteria. The Company further admits that they are indicative financial planning placeholders, not actual projects.

Second, as noted above, adding back feed lines is much like adding feeder tie-ins to allow for quicker restoration of service and less outage time. This should always be a goal of the Company and is something that the Company has done in the past in other areas of its territory. Furthermore, if individual customers like the Greensboro Coliseum and Charlotte Douglas Airport, need a back feed line to ensure uninterruptible service, there are tariff provisions in place for those customers to request one and bear those costs without burdening other customers who will realize minimal, if any, benefits from such projects. If the Company feels it is necessary to add a line due to the new load that an individual customer is adding, it should be considered new load growth and part of the Company's customary spend. All of the projects within the Distribution Hardening and Resiliency program are indistinguishable from projects that DEC constructs in its normal course of business, which makes it very difficult or impossible to determine which projects should be in Power Forward and which should be considered part of the Company's customary spend. Thus, the Commission concludes these projects should not be recovered through the Company's proposed Grid Rider.

Much like the Distribution Hardening and Resiliency program, the Transmission Improvements program also consists of projects that replace, rebuild, or improve existing transmission equipment. Of the $1.575 billion DEC budgets for this program, only $88.85 million is related to projects that do not explicitly state that they are for rebuilds, replacements, upgrades, or improvements. The remaining $88.85 million is comprised of substation animal mitigation ($20 million), Remote Sectionalizing Switches ($37.5 million), System Intelligence HRM & CBM ($30.55 million), and Install new Digital Fault Recorder ($800,000). Substation animal mitigation is not a new program, and while witness Simpson states it is critical for security, DEC has already installed similar mitigation techniques in other substations around its territory. Simpson testified that this program does expedite the replacement of obsolete and old design equipment to allow for newer proactive monitoring equipment. Simpson also stated that the Company has already installed some of this monitoring equipment throughout its territory. As to the substation upgrades, witness Simpson stated that the Company would have to look and see what state-of-the-art upgrades had been completed for each substation. Many of the projects in this program are also to ensure DEC remains compliant with federal NERC and CIP standards, as well as to improve the physical and cyber security of the transmission grid. The Commission is conscious of the need for the Company to protect against national security threats and comply with federal reliability standards, however, these are not new or discrete issues nor are they ones that can be eliminated with the projects incorporated in Power Forward. Physical and cyber threats will continue to be a part of the Company's ongoing responsibility long after Power Forward is projected to have ended. Unfortunately, these types of threats will continuously change and evolve, thus requiring DEC to adapt and evolve in order to continue to protect the grid and provide adequate and reliable service. Federal reliability standards such as NERC and CIP 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 those standards now and in the future just as it has done for decades. Simpson admitted that meeting these federal standards is customary as part of the Company's Business Expansion/Capacity expenditures. Therefore, this is not something that is outside of the Company's ordinary course of business.

The Commission finds that the Self-Optimizing Grid program is made up of projects that replace existing lines with larger conductor cable, add automated switches, and install new back feed and tie-in lines all of which enhance the grid's ability to accommodate two-way power flow. This program will make certain areas of the grid more "stiff" and increase capacity to enable more DERs to connect to the grid. The Commission notes that it has separately approved interconnection fees that allow DEC to recover interconnection costs directly from the developers and customers who seek to interconnect electric generating facilities to DEC's distribution facilities. See Revised North Carolina Interconnection Procedures, Docket No. E-100, Sub 101 (June 15, 2015). The Commission finds that DEC did not provide sufficient information to show how the Company will determine which of these projects would be appropriate for recovery through a potential Grid Rider and which should be directly 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 the new DERs on the system or new back feed or tie-in lines is unclear from the evidence presented. As stated above, the Commission does not find that back feed or tie-in lines represent either new work or grid modernization, as witness Simpson testified. In fact, the addition of these types 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. This project should continue to be part of the Company's ongoing effort to ensure adequate and reliable service to all its customers when it is reasonable and prudent to do so.

The Enterprise Systems and Communications Network Upgrade programs include upgrades to several systems the Company already utilizes to enable data acquisition and analytics to help control the grid. The Commission finds that these upgrades are no different than many upgrades to other systems the Company has made in the past and is currently 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. If the Company requested a rider every time it updated a monitoring system, there would be too many riders to count. The Company has provided little to no evidence concerning the function of these upgrades and how they will vastly improve grid operations.

The Commission finds and concludes that while DEC intends to expend significant funds for T&D projects over the next ten years, the Power Forward programs and projects proposed by DEC to be included in a Grid Rider are the types of activities in which the Company engages or should engage in on a routine and continuous basis.

<u>Establishment of a rider or deferral accounting for the costs of Power Forward is not appropriate</u>

DEC witness McManeus testified to the Company's request to recover the investments made in Power Forward through the Grid Rider. She stated that the rider will enable DEC to recover the cost of multi-year, planned, system upgrades on an annual basis as opposed to the traditional method of recovering costs. Unlike investments in generating plants, rate cases are not a timely match for large, non-revenue producing grid investments that occur over serval years. Witness McManeus indicated that the inability to collect amounts from customers in the same timeframe that the Company makes these investments will dilute cash flows and earnings, which could slow the pace of the investments to be made as part of Power Forward. (T 6 pp 269-70) Witness McManeus did concede during the hearing that the Company had not performed an analysis of cash flow with and without implementation of the Grid Rider. (T 6 p 442) She testified that the

Company believes this is a more fair method for recovering the cost of large dollar investments that are being placed into electric service rapidly. (T 6 p 270)

As for the mechanics of the rider, witness McManeus testified that the appropriate share of costs of Power Forward should be recovered from all North Carolina retail customers in the Grid Rider on an annual basis. The rider would include an annual true-up or Experience Modification Factor (EMF), similar to other riders established by the legislature. She specified that each year the proposed Grid Rider would include a projection of revenue requirements for a future billing period plus an EMF for a prior test period. The Company proposed the initial rider in this proceeding based on estimated revenue requirements for 2018. Witness McManeus explained that subsequent riders would be administered on a schedule that aligns with that provided for in Commission Rule R8-55 for the fuel adjustment clause, using the same test periods and billing periods. Ms. McManeus clarified that the Grid Rider is proposed as a supplement to rate changes through general rate cases. As such, in any future general rate case proceedings, the balance of any unrecovered amounts of Power Forward costs then being recovered through the rider would be incorporated into base rates. Because of this, prospective Grid Riders would include only incremental costs incurred after a rate case test period. Witness McManeus stated that, as with other riders, the annual proceedings will allow other parties to participate in the proceedings before the Commission. (T 6 pp 271-72)

Witness McManeus identified the types of costs that would generally be included in the Grid Rider to include the costs associated with transmission and distribution capital investments made as part of Power Forward and the related O&M expense. The revenue requirement associated with these expenditures would include depreciation and financing costs related to the rate base amounts plus incremental operating expenses, including income taxes and general taxes. (T 6 p 272) Ms. McManeus provided an original calculation of the estimated annual revenue requirement for 2018 Power Forward expenditures of $35.7 million, but filed a revised version during the hearing that showed expenditures of $32.235 million to reflect the change in the federal tax rate and the settlement weighted average cost of capital.

Finally, witness McManeus requested that if the Commission did not approve the Grid Rider that it allow DEC 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. Along with the regulatory asset, the Company requested that it be allowed to accrue a carrying charge on the deferred cost balance at the Company's approved weighted average cost of capital. (T 6 p 273)

During the hearing, DEC witness Fountain testified that historically utilities have made grid investments and then asked for those investments to be recovered in a general rate case, but DEC is now proposing a different model to go forward because it is a different era. He also pointed out that a number of other states are requesting these types of riders as well. (T 7 pp 31-32) When asked if the rider would eliminate regulatory lag, witness Fountain admitted it would eliminate some but not necessarily "a lot." (T 7 pp 33-34) Witness Fountain, however, was then asked several questions about Duke Energy's quarterly earnings calls, in which Steven K. Young, Duke Energy Corporation's executive vice president and chief financial officer, stated that "in North Carolina, we now have renewable energy riders established" and "we will continue to pursue these types of recovery mechanisms to enhance our investment returns" and that the company's "ultimate goal is modernization of the regulatory framework in North Carolina to allow more timely recovery of these investments" to which witness Fountain indicated that the Company is trying to address regulatory lag and avoid general rate cases. (T 8 pp 210-11) Witness Fountain also acknowledged that Duke Energy Corporation's earnings were growing steadily at a range of four to six percent due to investments that Duke is making, a big part of which is Power Forward. (T 7 p 27) Witness Fountain then stated that if the Company implemented Power Forward without the Grid Rider that there would be more frequent rate cases. (T 9 pp 56-57) He later testified that the Company would make grid modernization investments even if the rider was not approved. (T 6 p 431) Witness Simpson also stated that, from an operations standpoint, there is a need for Power Forward regardless of the cost recovery mechanism. (T 17 pp 80-81)

Witness Fountain reiterated that this rider would be similar to the other rider proceedings. (T 7 p 35) He described the proceeding as an advance review and not a preapproval process, which would give stakeholders an opportunity to provide input, but conceded that there are details of the rider that need to be determined if approved. (T 9 pp 91-92) He also stated that the Commission could, during any general rate case, decide whether to allow the rider to continue after the initial ten year Power Forward timeframe. (T 10 pp 47-48)

Public Staff witness Maness testified that riders not specifically established by statute, similar to deferral accounting, are 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 testified that any time the Commission splits apart one item or a group of items for single-item ratemaking, through either a rider or deferral accounting, it upsets the balance set by the precepts of G.S. 62-133. He explained that this is one of the reasons that the Commission has previously stated that deferral accounting and riders should be an exception, not the rule. Witness Maness stated that the Public Staff believes that the Grid Rider would upset that balance in a significant way. Witness Maness also indicated that it is important that items set aside for special treatment, such as riders and deferred costs, should be both extraordinary in magnitude and very unique in type. Witness Maness conceded that DEC intends to expend significant funds to complete Power Forward; the Public Staff, however, believes that many of the items proposed by DEC to be included in the Grid Rider are the types of activities in which the Company engages on a routine and continuous basis, with or without the modernization of the grid. As such these items are neither extraordinary nor unique. (T 22 pp 89-91)

Witness Maness went on to state that when a rider or deferral accounting is established, costs intended to be included in the rider should preferably be easily identifiable because of the issues and controversies that may arise over whether specific items of costs are eligible for inclusion in the rider. Witness Maness agreed with Public Staff witness Williamson that the types of plant items that the Company is proposing are somewhat vaguely described. Witness Maness warned that it is certainly possible that these types of disputes would regularly arise. (T 22 p 91)

Witness Maness stated that because of the nature of specific-item ratemaking, very careful vetting of items proposed to be included in the rider would be necessary on a recurring basis, putting substantial additional strain on Commission and Public Staff resources, as well as the resources of other intervenors. This is particularly true given the short time frames usually established for annual rider proceedings, especially when rider proceedings run concurrently. (T 22 p 91)

Witness Maness also testified that any time large amounts of recurring types of costs are split off from the regular ratemaking process, incentives restraining capital investment that are naturally present in the normal aggregated method of ratemaking practiced under G.S. 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. He explained that the Public Staff's investigation time in the various electric rider proceedings is considerably shorter than its investigation time in a general rate case. Furthermore, electric rider proceedings are "stacked" so as to run concurrently, thus further limiting Public Staff human capital resources to undertake a thorough investigation. Gone is any natural restraint imposed by the difficulties in mounting a general rate case proceeding. Adding another rider proceeding, especially one involving extensive capital investments, to the already compressed and time intensive electric rider proceedings would limit the Public Staff's and Commission's ability to thoroughly vet the Company's request. (T 22 p 92)

Lastly, witness Maness warned that 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. He testified that the Public Staff knows from experience that it can be much more difficult to bring a utility in for a rate decrease than it is for a company to propose and support a rate increase. (T 22 pp 92-93)

Witness Strunk, on behalf of the Tech Customers, testified that several significant factors distinguish DEC's proposal from the capital trackers approved by this Commission and other state regulators in the past. First, other trackers previously approved by the Commission were specifically authorized by statute.

Witness Strunk testified that he had been informed by counsel that there is no express statutory authority for the Grid Rider sought by DEC, and hence a legal uncertainty as to whether the Commission can authorize the rider without an enabling statute. In addition, as a matter of regulatory economics, an important distinguishing factor is the sheer size of the investment program (larger than either DEC's or DEP's rate base) and the fact that it will tilt the regulatory framework in favor of DEC and its shareholders by allowing it to replace a large share of its net plant in rate base over ten years without a general rate case proceeding. (T 26 pp 471-72)

Witness Strunk also testified that the Commission-authorized capital trackers he reviewed were part of efforts to comply with statutory or regulatory compliance mandates or to advance economic development efforts. By contrast, DEC is seeking to recover in its proposed rider new network investments that cannot easily be distinguished from its traditional network investments and are not a direct response to new regulations or government-directed initiatives. (T 26 pp 472-73)

Witness Strunk further testified that DEC's proposed use of a rider for such a large component of ongoing capital investment threatens to unbalance the regulatory process by avoiding periodic reviews of DEC's aggregate cost of service in the general rate case process, thereby risking a significant disconnect between rates and the Company's cost of service. The treatment of new network investments in general rate cases assures that changes in all aspects of the utility's cost of service are addressed and considered in the revenue requirement approved by the regulatory agency for the establishment of rates. This means that rates are reset taking into account the full picture of (1) the rate base, netting the effects of new capital additions and reduced plant balances for existing assets (resulting from greater accumulated depreciation); and (2) operating expenses, netting the effects of increased operating expenses (and depreciation) against any decreases in operating expenses (and depreciation) on other assets. DEC's proposed use of a rider for such a significant quantity of network investments would unbalance this regulatory process and would make it one-sided, *i.e.*, taking into account increases in net plant and operating expenditures without reflecting corresponding decreases in other areas of the utility's business. This unbalancing, given the sheer magnitude of the investments at stake, could lead to situations where the rates are significantly out-of-sync with the utility's cost of service. Strunk stated that the Commission expressed its concern about this risk in North Carolina and took comfort in the limited scope and size of the rider it approved in its Order for *In the Matter of Application of Piedmont Natural Gas Company, Inc. for a General Increase in its Rates and Charges,* Docket No. G-9, Sub 631, at p 39. It is of particular concern for Power Forward, given the proposed state-wide investment program of over $13 billion. (T 26 pp 473, 480-81)

CUCA witness O'Donnell testified that Company management has clearly and unequivocally stated that it intends to drive earnings in the future through grid investments. However, instead of taking the traditional route of spending its own money and then filing for cost recovery in a rate case, the Company is now seeking to defer risk onto consumers by asking for an automatic forward-looking cost recovery mechanism such as the Grid Rider. This effort to shift risk to consumers will allow DEC to make annual investments and obtain immediate rate treatment without the full review of all its other operating expenses. In essence, the Company is asking to be "deregulated" in terms of rate recovery while still holding complete franchise rights in a totally monopolistic service territory. (T 18 p 34) So, in essence, Company management has realized that, to continue to grow earnings, it has to stop focusing on building new generation plant and, instead, build something else. In this case, the "something else" is grid "modernization" plant. The core questions for this Commission are whether the Company's massive grid efforts are needed and, if so, are they cost beneficial and prudent expenditures for North Carolina consumers. The Company's discussion about economic growth from grid investments is a one-sided story because the Company fails to mention the economic harm to consumers due to the high costs of the Company's proposed grid updates. DEC's Grid Rider shifts risk to consumers, drives up electric rates, and does not provide guaranteed benefits commensurate with the $13 billion statewide price tag. (T 18 pp 37-41)

Several witnesses including CUCA witness O'Donnell, NCSEA witness Golin, and EDF witness Alvarez testified that a more open stakeholder process regarding DEC's grid modernization plans should be required. Witness Alvarez stated that stakeholder participation would better align grid modernization capabilities and investments with Commission and State priorities. (T 26 p 297) Witness Golin testified to the need for much stronger oversight, review and transparency before Power Forward is implemented. (T 67-68) Witness O'Donnell testified that one overriding theme in his analysis of various state actions concerning grid modernization is transparency and public involvement and to that end, the Commission should open up a separate docket to investigate the Company's need for Power Forward. (T 18, pp 48, 51)

Public Staff witness Williamson testified that there is substantial uncertainty regarding what exactly will be included in the Power Forward initiative. He stated that the Company's current description of Power Forward is extremely broad and open-ended. The extent of the planned investment and the potential impact on customer rates require additional information, which would assist the Commission and Public Staff in understanding Power Forward and evaluating its cost-effectiveness. He recommended that the Commission require the Company to file more detailed information on Power Forward in its annual Smart Grid Technology plan. (T 22 pp 36-37)

The Commission finds and concludes that riders not specifically established by statute should be considered an exception to the general ratemaking principles put in place by the General Assembly and this Commission. In the instant case, there is no statute or legislative guidance requiring the establishment of the Grid Rider and it, therefore, falls to the Commission to determine whether the circumstances presented by DEC rise to the level of being exceptional. The Commission finds that DEC has not presented exceptional circumstances because, as discussed above, neither Power Forward as a whole nor the projects that comprise Power Forward are extraordinary or unique. In fact they are the type of activities in which the Company engages in on a routine and continuous basis.

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. If the Commission were to establish the proposed rider, there would be very little that would be the subject of future general rate cases, other than coal ash and depreciation, as DEC has limited generating needs over the Company's planning horizon.[31] The Commission finds and concludes that if the Company were allowed to recover such a large portion of its capital expenditures through a rider, and not through base rates, it would upset the ratemaking principles set out above and discussed by Public Staff witness Maness. Allowing such a large amount of expenses and revenues to be recovered outside of a general rate case would upset the calculation of the rate of return in a significant way. The Commission further finds and concludes that the establishment of a Grid Rider as proposed, given its significant price tag, would increase the likelihood that the Company will exceed its allowed overall rate of return while making it more difficult for the Commission and the Public Staff to determine if the Company has in fact done so. It is more challenging for the Public

[31] See the Company's latest IRP update filed on September 1, 2017 in Docket No. E-100, Sub 147.

Staff or the Commission to require the Company to lower rates than it is for the Company to file and support a rate increase when necessary.

The Commission finds that when large amounts of recurring types of costs are separated from the normal ratemaking process, the restraints inhibiting capital investment that are naturally present in the normal aggregated method of ratemaking under G.S. 62-133 are relaxed in part due to the frequency of recovery. Due to these relaxed restraints, it is even more important for the Commission and the Public Staff to carefully vet the items proposed for recovery, which puts substantial strain on available resources. The investigation time in the context of a rider proceeding is significantly shorter than the investigation time in a general rate case. Furthermore, DEC's rider proceedings are "stacked" and adding a Grid Rider, with a vast amount of potentially disputed projects on top of the other riders, would stress resources.

DEC has raised concerns about the regulatory lag for its Power Forward investments. Regulatory lag in certain amounts can give company management an incentive to economize and require more confidence in its investments. Company witness Fountain stated that while the rider would alleviate some regulatory lag, it would not be a significant reduction. DEC witness McManeus stated that the Company did not do an analysis to determine the amount of cash flow with and without the rider; thus, there is no evidence on the record that the Company would be unable to carry out its operations without the requested annual recovery. Therefore, the Commission finds that DEC's regulatory lag concerns are unpersuasive.

The Commission finds that the Company's motivations for proposing the rider are not strictly limited to improving the performance and reliability of the grid to enhance customer service, but also to change the State's rate recovery mechanism outside of the legislative process. The Commission sees this rider proposal as not only a request to establish the Grid Rider but as the first step in setting precedent to allow for more riders to recover capital costs in the future. The Commission concludes that allowing more riders, particularly those that seek to recover large amounts of capital expenditures and O&M expenses, would shift much of the risk shared by customers and shareholders disproportionately onto the customers by having forward looking recovery methods applied outside of a general rate case. This would go directly against the public policy of Chapter 62, whose "[p]rimary purpose… is not to guarantee to stockholders of public utility constant growth in value of and in dividend yield from their investment, but is to assure public of adequate service at reasonable charge." *State ex rel. Utilities Commission v. General Tel. Co. of Southeast*, 285 NC 671, 208 S.E.2d 681 (1974). While there are reliability and operational reasons for DEC to be implementing Power Forward, the statements made by Duke Energy Corporation's Executive Vice President and CFO make it clear that the request for a rider is part of a larger plan to change the recovery method of capital investments and to drive and consistently grow earnings for shareholders. This is not an issue for the

Commission to address; therefore, we conclude that the Grid Rider should be denied.

Additionally, the Commission finds and concludes that:

> [T]he Commission has 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.
>
> The Commission 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.

Order Approving Deferral Accounting with Conditions, E-7, Sub 874, p 24 (March 31, 2009).

The Commission finds and concludes that a regulatory asset is a typical result of deferral accounting and that allowing DEC to establish a regulatory asset for Power Forward and then recover the deferred costs in a later general rate case would in essence be no different than allowing DEC to recover the costs of Power Forward through a rider at an earlier date. Therefore, the Commission denies DEC's request to establish a regulatory asset for the costs of Power Forward, largely for the same reasons that it denies the request for a Grid Rider.

Finally, the Commission finds and concludes that the parties have raised some valid concerns regarding the transparency of and details underlying DEC's Power Forward initiative. As discussed above, the Commission finds that a grid rider is not appropriate for the costs of Power Forward. However, additional information would be helpful to allow the Commission, Public Staff, and other interested parties to better understand Power Forward projects and to quantify their benefits.

Therefore, the Commission finds and concludes that DEC shall include in its smart grid technology plan filings, required by Commission Rule R8-60.1, more detailed information on: (1) the purpose of each project or categories 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 transmission and distribution assets affected by the project. The Company shall consult with the Public Staff regarding what information should be included and in what level of detail. Adding these requirements to the smart grid technology filings will allow the Commission, the Public Staff, and other interested parties to stay apprised of the Company's progress on Power Forward projects in areas that have already been identified in previous smart grid technology plans as well as new projects that further the goals of Power Forward.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 50-58

The evidence for these findings of fact and conclusions is found in the testimony and exhibits of DEP witnesses McManeus, Kerin, and Wright; Public

Staff witnesses Garrett, Moore, and Maness; Sierra Club witness Quarles; CUCA witness O'Donnell; and Attorney General witness Wittliff.

DEC DIRECT TESTIMONY

In their direct testimony, DEC witnesses contended that the coal ash costs included in the Company's rate request are costs of complying with new laws and regulations. Specifically, ash basins are being closed pursuant to the United States Environmental Protection Agency (EPA) "Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities; Final Rule" published in the Federal Register Vol. 80, No. 74, on April 15, 2015, (CCR Rule) and the North Carolina Coal Ash Management Act (comprised of Session Law 2014-122, Senate Bill 729; Session Law 2015-110, Senate Bill 716; and Session Law 2016-95, House Bill 630; collectively referred to as "CAMA").

In her direct testimony, DEC witness McManeus summarized the Company's request to recover the costs of ash basin closure and compliance from January 1, 2015, to November 30, 2017. She stated that the total system spend by DEP on coal ash basin closure during that period is $677.9 million ($170.2 million in 2015, $287.3 million in 2016, and $220.4 million in the 2017 projected period). (T 6 p 259)

DEC witness Wright testified that the coal ash costs in the present case are a "used and useful" utility cost, were prudently incurred, and proper for inclusion in rate base. He testified that DEC is in the best position to decide how to address coal ash disposal in conformance with State and federal coal ash disposal requirements. He also testified, however, that he had not reviewed the individual item costs or accounting records, so he could not reach a conclusion regarding the prudence of a specific level of costs or of individual cost items. (T 12 p 154)

DEC witness Kerin described the Company's coal-fired generation resources, the history of its ash handling, and the history of applicable regulations for coal ash management. He generally discussed the requirements of the CCR Rule, CAMA, and consent or settlement agreements and orders affecting closure of ash basins and other aspects of CCR management. His exhibits included the amount of ash and history of disposal for each plant, initial closure plans for ash basins, a breakdown of expenditures from January 1, 2015 through November 30, 2017, for coal ash compliance at each plant site, and a plant-by-plant summary of ash management cash flows for ARO purposes. Mr. Kerin testified that DEC's actions and expenditures have been reasonable, prudent, cost-effective, and designed to meet existing legal requirements. He also summarized DEC's request for recovery of ongoing CCR compliance costs, testifying that those ongoing costs are reasonable, prudent, and cost-effective options for ongoing CCR compliance.

INTERVENOR TESTIMONY

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. Mr. Garrett and Mr. 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, Mr. Garrett and Mr. 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. (T 18, pp 133-34)

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 that were not required by law or where lower-cost compliance options were available, which they described in further detail in their testimony. (T 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 G.S. 130A-309.211(c)(1) and performing the applicable dam safety repair work at these sites. (T 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 G.S. 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. Therefore 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. (T 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 G.S. 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. (T 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 G.S. 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 G.S. 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. (T 21 pp 59-61) Mr. Moore therefore recommended that the Commission disallow the $10 million already incurred by DEC for the cementitious beneficiation project at Buck. (T 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. (T 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, Mr. Moore found no valid technical reasons why an adequately sized on-site landfill could 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. (T 21 pp 64-66)

As a result of DEP'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. He 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. (T 21 p 70) Mr. 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. Mr. Moore instead testified that the DEC-owned on-site landfill at the Marshall Facility should have been utilized for the disposal of all ash from Riverbend. (T 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, Mr. 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. (T 21 pp 72-74)

Witness Garrett focused his testimony on the activities undertaken by DEC at its W.S. Lee site in South Carolina. Mr. 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. (T 21 pp 39-40) Mr. Garrett also concurred with DEC's decision to take some actions at the 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. Mr. 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. Mr. Garrett further stated that DEC failed to provide a regulatory or technical reason to substantiate immediate removal of the ash from the IAB. Mr. 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. (T 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, since 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.)

DEC REBUTTAL TESTIMONY

DEC witness Kerin filed rebuttal testimony on February 6, 2018, in which he noted that Public Staff witnesses Garrett and Moore had conducted a robust analysis and investigation. He indicated that he agreed with a majority of their conclusions, but stated that given the scope and magnitude of the information they had to investigate and the time in which they had to conduct their investigation, they missed or overlooked key facts in several of their recommendations. (T 24 pp 90-92)

First, Mr. Kerin disagreed with witness Moore's conclusion that it was unreasonable and imprudent for DEC to transport CCR material from Dan River until an on-site landfill could have been constructed. He specifically disagreed with witness Moore's conclusion that a greenfield on-site landfill could have been built on the western portion of the Dan River site, eliminating the need for DEC to transport ash from Ash Stack 1 off-site. Mr. Kerin stated that multiple factors, including community interests, environmental concerns, health and safety risks, and geological and topological features made locating the landfill on the western boundary an impractical alternative. (T 24 pp 92-94)

Mr. Kerin testified that DEC did explore on-site and off-site landfill options to accept the ash from Dan River, and in June 2015 acquired two adjacent parcels (referred to as the “Hopkins Tracts”). However, due to changes made by the City of Eden to the zoning that were applicable to those properties, construction of a landfill on these properties became cost-prohibitive. DEC then entered into an agreement in July 2015 (“Eden Agreement”) by which the City of Eden amended its zoning ordinance to allow construction of a landfill, subject to certain limitations, including: (1) that the landfill had to be located on the Dan River property; (2) that the on-site landfill be located “near the existing basins;” and (3) that the landfills be located as remote from residential areas as feasible. (T 24 p 95) DEC therefore determined that the footprint of the former Ash Stack 1, which DEC had already been excavating and hauling off-site was the best location for the landfill pursuant to the Eden Agreement. Mr. Kerin testified that the proposed on-site location identified by Mr. Moore would not have complied with the Eden Agreement because it was not the closest location to the existing basins, nor was it as remote as possible from adjacent residential areas. (T 24 p 96)

Mr. Kerin then indicated several other reasons why he did not believe that Mr. Moore’s recommended landfill location was a feasible option, including the existence of a land clearing and inert debris (“LCID”) landfill in his proposed landfill footprint that contained asbestos-laden materials, wetlands and streams located in the footprint, elevation and topographic features, line of site conditions, bedrock depth, and stormwater permitting concerns. (T 24 pp 97-102)

Mr. Kerin also indicated that Mr. Moore's proposed disallowance for the Dan River site was incorrectly calculated, because he underestimated the costs off excavating materials from the LCID Landfill, the costs to relocate a warehouse building on the site, and his inclusion of some costs associated with ash from the Primary Ash Basin, as opposed to the Ash Stack 1. (T 24 p 104)

With regard to Mr. Moore's recommendation that Duke should have selected DEP's Weatherspoon facility over Buck as a beneficiation site, Mr. Kerin testified that the products being sold from Weatherspoon were different than that from Buck and used for different purposes. He stated that the ash from Weatherspoon was being sold to cement manufacturers to be used as raw material or aggregate in the manufacture of cement, while the beneficiated ash from Buck was being sold as a replacement for cement. Mr. Kerin also stated that the quantity of ash at the Weatherspoon site was not sufficient to support the investments necessary to beneficiate the ash, and it was in a poor geographic location with regard to the proximity to major markets for ash used in the cement industry. (T 24 p 106) He further testified that the language in G.S. 130A-309.216 that called for the "the installation and operation of an ash beneficiation project" and "produc[tion]" indicates to me that the General Assembly intended for Duke Energy to construct and operate technology, such as carbon burn-out plants and STAR technology, and that basic drying and screening operations such as those implemented at Weatherspoon would qualify as beneficiation for cementitious purposes. (T 24 p 107)

In response to Mr. Moore's conclusion that it was inappropriate for DEC to have trucked ash from Riverbend to the R&B Landfill in Georgia instead of using on-site landfill capacity at DEC's Marshall facility, Mr. Kerin stated that DEC had only 60 days from the date on which it received its NPDES Stormwater Permit at Riverbend to begin coal ash removal, and that short excavation deadline required DEC to identify a party that could haul and dispose of the Riverbend ash on a short turnaround. DEC therefor entered into a contract with Waste Management to transport 1,000 tons per week for 17 weeks. Mr. Kerin further noted that it did not receive approval from DEQ to dispose of ash from Riverbend at Marshall until June 19, 2015, which did not allow enough time to take actions necessary to utilize Marshall and still meet the 60-day deadline. (T 24 pp. 108-11)

Mr. Kerin also took exception with Mr. Garrett's position that Duke should have delayed excavation of the Inactive Ash Basin ("IAB") at W.S. Lee and instead undertaken grading and slope stabilization to reduce geotechnical concerns raised with the IAB. Mr. Kerin stated that the recognized stability issues and on-ground conditions at the site, as well as the regulatory environment in South Carolina at the time would have made Mr. Garrett's recommendation imprudent. Mr. Kerin stated that based on a stability analysis done during that time, the IAB did not meet the required dam safety factors for maximum pool storage and liquefaction conditions, and therefore DEC decided to begin excavation immediately. Mr. Kerin also noted that Duke Energy entered into a consent agreement with SCDHEC in September 2014 that required DEC to excavate the IAB. Mr. Kerin noted that DEC's analysis of the IAB identified a number of issues, including:

> large tree growth on the dike, including the potential root ball destabilization from toppled trees, scarps and sloughs driven by the Saluda River scouring and undercutting the bank along the base of the dike, and stability factors of safety under various conditions including global dike stability, temporary loading conditions, and seismic and liquefaction issues. (T 24 p 113)

Mr. Kerin further testified that two pipes terminated at the river from under the IAB and that in DEC's communications with SCDHEC, the regulator was "adamant that DE Carolinas eliminate potential short-term or long-term release from these pipes." (Id.) Based these factors, DEC determined that immediate excavation was the most reasonable course of action.

Mr. Kerin also testified that the two-phased approach proposed by Mr. Garrett could have proven unsafe due to limitations on equipment access to the dike crest and resulted in additional time delays to obtain necessary permits. Further, Mr. Garrett's proposed approach would not have addressed some of the liquefaction concerns and resulted in the exposure of some ash directly to the exterior of the dike. (T 24 p. 114). Mr. Kerin stated that the primary goal of the Consent Agreement was to take prompt action to excavate ash, which would address the concerns expressed by SCDHEC. This included not just the ash contained in the IAB, but also the Old Ash Fill area. (T 24 pp 115-16)

As a final issue regarding W.S. Lee, Mr. Kerin stated that as part of its agreement with SCDHEC and environmental groups, DEC agreed to manage all ash on-site through a single lined landfill, and that combining the ash from the Structural Fill area with the on-site landfill mitigated future risk and avoided potential future cost increases had the work been required at a later date. (T 24 p 116)

COMMISSION REVIEW OF EVIDENCE AND CONCLUSIONS

The Commission in this proceeding is asked to address the reasonableness and prudence of DEC's coal ash costs and the regulatory treatment of coal ash costs. Unreasonable costs, which may include costs resulting from imprudence, are properly disallowed under G.S. 62-133(b). The Commission has stated the prudence standard as follows:

> the standard for determining the prudence of the Company's actions should be 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. The Commission agrees that this is the appropriate standard to be used in judging the various claims of imprudence that have been put forth in this proceeding…and adopts it as the standard to be applied herein. 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.

78 North Carolina Utilities Commission Report, 238 at 251-52 (1988).

As discussed throughout this proceeding, multiple factors have impacted DEC's coal ash management practices over the past four years, most significantly the discovery of extensive coal ash-related violations of long-standing environmental laws and regulations, the enactment of new regulatory requirements in CAMA and CCR, along with legal requirements resulting from settlements, consent orders, and plea agreements. These factors resulted in the establishment of timeframes for the closure of facilities, accelerated remediation measures at multiple sites, and the expenditure of hundreds of millions of dollars. Our decisions on the utility's prudence must be based on what was reasonably known or reasonably should have been known at the time the management decisions were being made. This is the Commission's first opportunity to review the reasonableness and prudence of these costs, but the Commission's traditional reasonable and prudence standards still apply.

During the hearing, the Public Staff placed a great amount of focus on the thoroughness of DEC's evaluation of all options, and whether DEC's decisions were made based on sound scientific or engineering principles, as opposed to other factors such as compliance with settlements or agreements that were reached to avoid litigation and potential liability, to reduce local community opposition, or to reduce future risk to a greater degree than required under applicable laws and regulations. For example, in its testimony and during cross-examination of DEC witnesses, the Public Staff repeatedly referred to the agreements reached with SCDHEC regarding W.S. Lee, with the City of Eden regarding the coal ash impoundments at Dan River, and the settlement reached with environmental groups requiring the excavation of ash from Buck. The Public Staff challenged whether these actions were taken by Duke to not only help ensure

Duke's compliance with the requirements of CAMA, the CCR Rule, and other regulatory obligations, but to also obligate DEC to accelerated timelines or additional work than otherwise would have been required of the Company. DEC also relied on these settlements and agreements to as evidence of the necessity for the actions taken by Duke and the associated expenditures, as well as for indicating why other lower cost options may not have considered.

The Commission must consider not only the utility's decision to enter into settlements and agreements when evaluating the reasonableness and prudence of the costs incurred, but must also evaluate the additional obligations the utility incurs as a result of the agreements. As discussed elsewhere in this order, the Commission remains concerned about the potential for settlements and other agreements to create a "moral hazard" by incentivizing Duke to potentially agree to requirements beyond those required by law under the auspices of the settlement or other agreements that ultimately result in higher costs being borne by its customers. The Commission must evaluate these management decisions in the context of a general rate case where prudency issues can be appropriately considered, and Duke presents these settlements and agreements as evidence of the reasonableness of its actions. Other parties evaluating DEC's actions are then required to identify and produce evidence demonstrating that other reasonable, lower cost alternatives to those actions were available to the Company at the time. If the Commission were to simply accept the settlements and agreements entered into by DEC as meeting that burden of proof, the Company is provided an incentive to agree to additional clean-up costs and more extensive remediation options than would otherwise have been necessary, since it would have increased assurance of its ability to recover those costs from customers.

The Commission reaffirms that DEC still maintains the burden of proof to demonstrate not only that the decision to enter into the settlement or agreement was reasonable. This means Company has an obligation not only to demonstrate that it made reasonable efforts to evaluate other alternatives available to it at the time, but also that the conditions that the Company agreed to as part of the settlement or agreement were constructed in a way that did not expand the obligations placed on the Company beyond what was necessary for compliance with its regulatory obligations.

The Commission's review of DEC's closure actions to date also points to the challenge of any prudency review. Under prevailing procedural and evidentiary standards, the Company's expenditures should be presumed to be reasonable and prudent until an objecting party provides evidence suggesting to the contrary, at which point the Company bears the burden of proof to substantiate the reasonableness of the expenditures. When the matter under review involves the reasonableness and prudence of a known and discrete expenditure made at a definite point in time, it is appropriate to require that parties challenging that expenditure come forward with some evidence that reasonable alternatives were available and to quantify the amount of the alleged error. *See State ex rel. Utils. Comm'n v. Conservation Council of North Carolina,* 320 S.E.2d 679, 312 N.C. 59 (1984).

In the DEP Rate Case, DEP argued that no party other than the Public Staff attempted the initial prong of this procedure, and that the Public Staff did so only with respect to the discrete items of expenditure recommended for disallowance by witnesses Garrett and Moore and by witness Lucas. Similarly, in this case the Public Staff was the primary party that sought to identify specific discrete items that should be disallowed on prudence grounds. The Commission is mindful of the enormous discovery process in a large, complex proceeding such as this one, and the weight of the burden on both the Company and intervenors in such circumstances is not insignificant. The Public Staff and other parties indicated that in the conduct of their investigation, there were multiple responses received from the Company indicating that "no responsive documents" were available, and many of the documents that were most heavily discussed in this proceeding were not the result of responsive information from the Company, but instead were identified independently by intervenors or required outside analysis to develop.[32] This information is critical for the Commission to test the sufficiency of the information on which the Company's decisions related to coal ash management were based, and whether the Company has met its burden of proof.

The Commission notes that these factors create additional complexity when evaluating the reasonableness and prudence of the decisions to incur costs made by the utility, particularly in circumstances where DEC selected closure options that may have increased the overall costs it faced in part to reduce future risk or

[32] See e.g,, T 15 p 77, T 16 p 27, T 24 p 194.

uncertain obligations. The Commission keeps these factors in mind as it evaluates the closure actions taken by DEC at each of its coal ash impoundments below:

Prudence of Dan River Closure Costs

Public Staff witness Moore's general premise is that DEC did not fully evaluate the feasibility of on-site landfill options at the Dan River site before proceeding with the excavation and off-site transportation of ash material from Ash Stack 1, and therefore the added costs incurred for off-site transportation of the CCR material was imprudent.

Public Staff witness Moore first took exception to the position taken by DEC that the timing of DEC's decision to proceed with excavation of Ash Stack 1 was driven in part by the moratorium combined with the aggressive closure deadlines for High Priority sites under CAMA. This was not the case.

The Commission notes that the moratorium enacted in Section 5.(a) of CAMA in 2014. (T 18, pp 148-49) Section 5.(a) provides:

> There is hereby established a moratorium on construction of new or expansion of existing coal combustion residuals landfills, as defined by G.S. 130A-290(2c) and amended by Section 3(d) of this act. The purpose of this moratorium is to allow the State to assess the risks to public health, safety, and welfare; the environment; and natural resources of coal combustion residuals impoundments located beneath coal combustion residuals landfills to determine the advisability of continued operation of these landfills.

As noted by witness Moore, the moratorium prohibited the construction of a new or expansion of existing coal combustion residuals landfill, which is defined in G.S. 130A-290(2c) as:

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

The moratorium would have prevented DEC from building a landfill within the footprint of the existing basins, such as the footprint of Ash Stack 1, during the period in which the moratorium was in effect. The moratorium did not, however, impact in any way DEP's ability to construct a new on-site landfill on what would be considered a greenfield site, i.e., a site that was not "located wholly or partly on top of a facility that is, or was, being used for the disposal or storage of such combustion products." DEP witness Kerin agreed that Ash Stack 1 was not subject to the August 1, 2019, closure deadline, and that the moratorium did not apply to on-site greenfield landfills. (T 15 pp 125-27)

The Public Staff noted that Mr. Kerin's testimony repeatedly conflated these issues – the timeline for CAMA closure of the Primary and Secondary Ash Basin at Dan River, and its initial decision to begin moving ash from the unregulated Ash Stack 1, which was not subject to the closure deadline. (Id.) While DEC's decision to move the Ash Stack 1 materials ultimately allowed it to utilize the footprint of that area for an on-site landfill, it did not need to be done in the timeframe upon which DEC selected, which significantly increased its closure costs.

The Public Staff presented evidence that Duke had previously considered the combined footprint of Ash Stack 1 and Ash Stack 2 in January 2014 as an on-site landfill option, with a plan to move the ash from the Primary and Secondary Ash Basins to the ash stack area, allowing the liner for the new landfill to effectively serve as a cap for Ash Stack 1 and 2. (Public Staff Kerin Direct Cross-Examination Exhibit #6, T 15 p 131.) Due to events taking place later in 2014, along with the moratorium enacted by CAMA, as along with the potential risk associated with the CCR material in the ash stacks remaining in an unlined capacity, this option was removed from consideration. As previously noted, the Public Staff took no exception with DEC's decision to move the CCR material from Ash Stack 1 to a lined impoundment since it did help to reduce long term risk. The Public Staff did, however, take exception to the timing and location for placement selected by DEC, noting that lower cost on-site landfill options should have been fully evaluated.

Mr. Moore and attorneys for the Public Staff placed significant weight on the April 28, 2014 AMEC Draft Letter Report – Landfill Siting Study for Dan River Steam Station (Public Staff Kerin Cross Examination Exhibit No. 7). The Public Staff pointed out that this report indicated that DEC in the early stages of its ash basin closure response had reasonable information indicating the cost-effectiveness of on-site landfilling options, options relative to neighboring properties, as well as off-site hauling by truck or rail. (T 16 pp 18-20) Mr. Moore testified that had DEC continued to pursue the initial conceptual analysis done on Dan River, it would have avoided significant expenditures.

Relying on the April 28, 2014, AMEC Report, the Public Staff presented evidence indicating that the landfill siting study that was prepared for DEC prior to determining its closure plan at Dan River evaluated both on-site and adjacent CCR landfill options, both of which were significantly more cost-effective than all off-site disposal options. (Id.) This report also identified an on-site greenfield location that could have handled not just the ponded ash in the Primary and Secondary Ash Basins, but also the stacked as in Ash Stack 1 and Ash Stack 2, with a footprint of approximately 38 acres. (Id. At pp 20-21). On rebuttal, Mr. Kerin agreed that the Option 2 Lined Landfill Onside specified steps requiring the movement of ash material from Ash Stacks 1 and 2, as well as the “ponded ash” in the Primary and Secondary Basins, indicating that a suitable on-site location for a greenfield landfill had been identified as part of their original siting study. (T 24 pp 206-08) This option was also identified in the report as being the lowest cost option for managing all of the coal ash materials at the Dan River site.

When asked on cross-examination about the location evaluated by AMEC for the on-site landfill, Mr. Kerin indicated that he was not familiar with the proposed locations. (Id.) In his testimony, Mr. Moore identified an area on the western boundary of the Dan River Site that in his professional opinion was a potentially suitable landfill site that should have been evaluated by DEC. (T 21 p 84) When asked in discovery about their analysis of on-site landfill options, including specifically this western area, DEC's responses to the Public Staff were "no responsive documents were identified." (T 16 p 27)

In rebuttal, DEP witness Kerin testified that Public Staff witness Moore overlooked significant factors that made the on-site landfill impracticable, including the presence of asbestos laden materials in the LCID landfill, wetlands and streams located in the footprint identified by Mr. Moore, elevation and topographic features, line of site conditions, bedrock depth, and stormwater permitting concerns. (T 24 pp 97-102) However, Mr. Kerin affirmed on cross-examination that the LCID landfill permit application and disposal records provided by DEC in response to discovery indicated a significantly lower amount of materials located in the LCID landfill that would have to be excavated and relocated than the conservative estimate utilized by Mr. Moore in his analysis. (T 24 pp 195-96) Further, Mr. Kerin agreed that under the permit for the site, the asbestos-containing materials were required to be double-bagged. (Id. at 199) Lastly the Public Staff also acknowledged that DEP had recently excavated and removed asbestos-laden materials from a disposal site at Sutton in order to construct new electric generating facilities on that property, and that this unexpected requirement did not present any insurmountable problems for the facility's construction timeframe. (T 21 p 164)

With regard to the wetland and stream concerns, Mr. Kerin acknowledged that while DEC would seek to avoid and minimize wetland and stream impacts wherever possible, where wetlands impacts and stream crossings are required there is a process to seek approval of the necessary permits and mitigation actions. (T 24 pp 98-100) In particular, Mr. Kerin acknowledged that DEC had to obtain Section 401/404 permits to construct two stream crossings to accommodate the rail hauling infrastructure at the Dan River site to allow for the off-site transportation of the ash from the facility. (T 24 pp 199-201) This impact could have been equally minimized with the decision to manage all of the CCR materials on-site.

Both DEC and the Public Staff presented evidence regarding the elevation and topographic features, line of site conditions, bedrock depth, and other siting concerns regarding the on-site landfill, but the Commission declines to take a position as to the merits of either parties' arguments on the feasibility of the site. (T 21 p 90-108) This dialogue was not resolved in the context of the hearing, as DEC presented additional evidence challenging the suitability of the site, and the Public Staff countered with additional information to address DEC's the additional concerns raised by DEC. Instead, the Commission relies on the principle that DEC initially bore the burden of proof to demonstrate that it had made reasonable efforts to evaluate the feasible options for managing the CCR materials at the Dan River facility in a cost-effective manner, and that they failed to meet this burden. Based on the evidence presented in this case, the Commission finds that DEC did not sufficiently evaluate all on-site options before commencing its off-site transportation and hauling of ash at a significant cost to customers.

In addition, Mr. Kerin also acknowledged that DEC's initial excavation activities focused on Ash Stack 1, which was not even subject to the aggressive closure schedule. Had DEC's primary focus been on compliance with the timeframes in CAMA, it would have commenced actions on the Primary and Secondary Ash Basins, rather than incurring significant costs and tying up resources on the excavation of basins that were not subject to early closure deadlines. DEC's closure schedule for Dan River also included the disposal of all coal ash, including from areas that were not subject to the August 1, 2019, closure deadline, indicating that DEC established an overly demanding schedule to achieve closure than called for within the CAMA timeframe. (T 15 pp 125-26)

With regard to the zoning concerns and the Eden Agreement, Mr. Kerin testified that the initial zoning of the Dan River property was identified in the AMEC Report as I2, which DEC's consultant in 2014 indicated was consistent with allowing a coal ash landfill. (T 16 pp 16-17) On cross-examination, the Public Staff raised the question of whether the zoning changes in December 2014 and January 2015 were prompted by the Town of Eden's concern with the development of a landfill on the Hopkins Tract, which it viewed as a key property for future industrial and economic development within the City. (T 24 pp 213-16) The Public Staff presented evidence indicating that DEC and the Town agreed on changes that would allow the landfill to proceed on the Dan River Site, in exchange for certain rights to be granted to the Town with regard to the Hopkins Tract. (Id.) By this time, however, DEC had already committed to moving the Ash Stack 1 materials already off-site at significant expense.

The Public Staff on cross-examination of DEC witness Kerin also highlighted that the General Assembly in its original enactment of CAMA included language in G.S. 130A-309.205 that provided for a preemption of local ordinances that regulated the management of coal combustion residuals and coal combustion products. (T 16 p 32) When asked if DEC had ever utilized this provision, DEC witness Kerin indicated that he was not aware of any circumstances where DEC had acted under the statute to keep local government actions from limiting their ability to manage coal ash on-site at its facilities. (Id. at 33)

The Commission acknowledges that the siting of coal ash landfills is not without controversy and has the potential to result in local community and local government opposition to the siting of landfills within their jurisdictions. The General Assembly also recognized this, and in order to keep this potential opposition from eliminating cost-effective storage options for CCR material, enacted G.S. 130A-309.205 to create a process by which such local government actions could be preempted or challenged by the utilities in order to save costs and ensure timely compliance with CAMA and CCR. Nonetheless, DEC has failed to utilize these provisions, and instead has chosen to settle these issues separately with agreements that resulted in significant increases in the closure costs incurred. To the extent DEC has taken such actions without fully utilizing the measures provided by the General Assembly to reduce these costs or time constrains, it is incumbent upon the utility to demonstrate that bringing a successful challenge to the local government ordinance under G.S. 130A-309.205 would not have resulted in cost savings to customers or improved the utility's compliance position. That is not the case in the Dan River context. DEC failed to fully evaluate on-site options, and then relied on the agreement reached with the City of Eden as evidence supporting their inability to proceed with an on-site landfill in a timely fashion. In this case, the Commission agrees with the Public Staff and finds that the costs incurred by DEC as a result of its decision to transport the CCR material from Ash Stack 1 (approximately 40% of the CCR material at Dan River) off-site was imprudent. Therefore the Commission finds that the premium of $59.2 million associated with this action, as identified by Public Staff witness Moore, should be disallowed from DEC's request in this proceeding.

It is incumbent that parties intervening in this case and conducting discovery be able to rely on the accuracy and completeness of responses from the utilities. The Commission finds that it was reasonable for the Public Staff to rely on the information provided by DEC in response to Public Staff data requests regarding the construction, permitting, and operation of an on-site landfill facility at Dan River, while taking into consideration the purpose for which of the documents were created. These documents help provide relevant insight in this prudency analysis as to the information available to management at DEC at the time the closure decisions in question were being made. Ultimately, however, the burden of proof is on the Company to support the prudence of its coal ash expenditures. In this case, it failed to meet its burden to demonstrate that it sufficiently evaluated the options for on-site management.

Prudence of Riverbend Closure Costs

As stated in his testimony, Public Staff 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. (T 21 p 86) DEC did not submit testimony to rebut this statement. Mr. Moore instead testified that the DEC-owned on-site landfill at the Marshall Facility should have instead been used to handle the additional ash from Riverbend. The Commission agrees with Mr. Moore 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. While Mr. Moore did not recommend a disallowance based on this decision by DEC, the Commission factors this decision in its overall evaluation of DEC's coal ash management actions, and finds that DEC in any future proceedings should fully demonstrate that it has fully evaluated on-site landfill options, as well as disposal options at other existing utility-owned facilities prior to entering into new obligations that may result in increased costs or risk to customers if the need for those alternate locations does not fully materialize.

With regard to Mr. Moore's recommended disallowance of the increased costs associated DEC's decision to haul approximately 17,000 tons of CCR material from the Ash Stack Area at Riverbend by truck to the R&B Landfill in Homer, Georgia, rather than utilizing the landfill at the Marshall Facility, the Commission agrees with Mr. Moore. The Marshall facility was closer in proximity and offered much lower disposal costs. In addition, while the facility was not initially permitted to accept CCR material from other facilities, the Public Staff presented evidence that not only was this option contemplated and discussed with DEQ as far back as 2009, the actual approval required from DEQ was straightforward and could have been obtained by DEC without jeopardizing their compliance timeframes at Riverbend. (T 24 pp 186-89)

Mr. Kerin points to the letter dated August 13, 2014, NC DEQ Secretary John Skvarla (attached to Mr. Kerin's Rebuttal testimony as Exhibit 6) that requested that Duke Energy submit an excavation plan for its impoundments at Riverbend no later than November 15, 2014, and to also begin coal ash removal at Riverbend "within 60 days of receiving required approvals" by NC DEQ. Mr. Kerin suggests that the NPDES Stormwater Permit issued on May 15, 2015, was the triggering event for the 60-day excavation deadline, and that DEC only had a short turn-around to identify options for the transportation and disposal of CCR materials from Riverbend. (T 24 pp 182-84) The Public Staff argues that DEC, having previously explored this option with DEQ, could have made this request at a much earlier point, avoiding the rush that DEC created for itself. It also noted that the permit modification to allow the disposal of coal ash from Riverbend at Marshall, submitted on June 4, 2015, only took 15 days to be approved. (Id.) The Commission, however, does not need to make a determination that DEC was required to act because of the 60 day notice of excavation schedule requirement starting on May 15 would not have allowed time for DEC to receive confirmation from DEQ regarding their requested permit modification. The permit modification submitted by DEC on June 4, 2015, was in itself a “required approval” by DEQ, so the timeline on the 60-day excavation requirement had not even commenced. Based on the information presented, the Commission finds that had DEC proceeded in a reasonable fashion with its permitting process and coordinating of transportation and disposal options, it had sufficient time to make transportation arrangements for the ash placement at Marshall and avoid the self-imposed rush that resulted in a most expensive disposal option being unnecessarily selected. The Commission further notes that any associated short delay resulting in the consideration of the Marshall permit modification by DEQ would not have had any meaningful impact on the overall closure schedule for the Riverbend facility, which based on the January 31, 2018 Environmental Compliance Plan Compliance Officer’s Report, DEC is anticipating completion of excavation at Riverbend by July 31, 2018, is more than one year ahead of schedule, including the excavation of the Ash Stack and Cinder Pit areas that are not subject to the CAMA closure deadlines. (T 24 pp 178-79; see Public Staff Kerin Rebuttal Exhibit 2).

<u>Prudence of W.S. Lee Closure Costs</u>

The Public Staff’s investigation of the coal ash expenditures by DEC at the W.S. Lee facility in South Carolina focuses on three main questions. First, did DEC fully evaluate its options to make necessary modifications at the IAB to allow the CCR materials in the basin to remain in place until the on-site landfill was prepared to receive ash, rather than immediately beginning excavation and transportation of the waste off-site; second, was DEC’s inclusion of the ash from the Old Ash Fill in its excavation plan reasonable; and third, were the off-site disposal options that DEC selected and the costs associated with those options reasonable? The Commission discusses each of these points in further detail below.

As previously discussed in the DEP case, one of Duke Energy's guiding principles is to minimize impacts to local communities, such as through reduced trucking and traffic congestion, and one way that helped meet this principle was through management of ash on-site to the greatest extent possible. Public Staff witness Garrett testified that on-site management generally results in much lower costs, lower risk compared to off-site disposal, and to some extent may generate less controversy than off-site disposal. (T 21 pp 39-40) DEC witness Kerin stated that DEC has agreed to manage all remaining on-site landfill option at the W.S. Lee facility, but noted that DEC has already completed the excavation of the IAB and the Old Ash Fill, with the materials being transported by truck to the R&B Landfill in Homer, Georgia. (T 24 p 112)

Public Staff Witness Garrett testified that he did not agree with DEC's decision to immediately begin excavation and transportation of ash to the R&B landfill in Homer, Georgia. Mr. Garrett instead testified that DEC should have instead followed the recommendations of its consulting engineers, which recommended repair and maintenance on the IAB berm in 2014, rather than immediate excavation. Mr. Garrett further stated that DEC failed to provide a regulatory or technical reason to substantiate immediate removal of the ash from the IAB or the Old Ash Fill. (T 21 p 40)

In his rebuttal testimony, Mr. Kerin stated that SCDHEC had "expressed concerns" regarding the IAB, but in response to discovery by the Public Staff, the only correspondence from SCDHEC related to the IAB addressed concerns over two corrugated pipes that terminated at the Saluda River from in and under the IAB. Mr. Kerin further stated that "[i]n DE Carolinas' communications with SCDHEC, the regulator was adamant that DE Carolinas eliminate potential short-term or long-term release from these pipes." (T 24 p 113) The Public Staff requested copies of this correspondence and agreed that SCDHEC expressed concerns over the pipes. The Public Staff noted, however, that the correspondence also showed that DEC submitted plans to grout the pipes to address SCDHEC's concerns in July 2014. (Public Staff Kerin Direct Cross-Examination Exhibit No. 4) With regard to any further concerns about the IAB expressed by SCDHEC, specifically with regard to the slope repairs recommended by Mr. Garrett, the Public Staff presented evidence indicating that in response to discovery specifically requesting support for these concerns stated by SCDHEC, Duke responded that with the response "No responsive documents." (T 24 p 194) Mr. Kerin when asked about these concerns stated that all of these concerns were expressed through "verbal, face-to-face meetings with the regulators in South Carolina" (Id.) No notices of violation were presented or other evidence of concerns by SCDHEC to confirm the need for the expedited treatment of the excavation and off-site disposal from the IAB and the Old Ash Fill. While Mr. Kerin testified that the consent agreement called for excavation of the IAB, the Old Ash Fill, "and any other areas where ash may have potentially migrated from these sites," he presented no evidence that ash had migrated from the Old Ash Fill at W.S. Lee as the basis for including the excavation of this facility in the Consent Agreement. (T 15 pp 110-11)

The Public Staff also cross-examined Mr. Kerin regarding the development of the consent agreement, and Mr. Kerin agreed that the original draft consent agreement provided by SCDHEC did not call for excavation or removal of ash from any facility at W.S. Lee, but simply called for the development of a remedial plan for the site. (T 24 p 193) DEC submitted the remedial plan the requirement to excavate all ash from the IAB and the Old Ash Fill area, which was incorporated into the final consent agreement. (Id.)

The Public Staff also notes that DEC had already conducted bidding events for the off-site transportation and placement of CCR materials at W.S. Lee in July 2014, before any information supporting need for excavation had been developed or finalized. (T 15, p 120). In addition, the Public Staff submitted evidence demonstrating that Duke entered into settlements with Save our Saluda and Upstate Forever in September 2014 indicating that in exchange for Duke's decision to excavate the IAB and the Old Ash Fill at W.S. Lee and place the material in a lined storage area, the conservation groups would agree not to take any legal action, including notices of intent to sue under Federal Clean Water Act. (T 15 p 123)

Both Public Staff witness Garrett and DEC witness Kerin presented a significant amount of testimony regarding the geotechnical concerns identified by DEC's consultants, S&ME. The parties disagree, however, on the content and timing of the specific recommendations. Mr. Garrett relied on the specific recommendations of the engineering firms hired by DEC, S&ME and URS, both of which he stated recommended repair and maintenance of the IAB berm in July and September 2014, but did not recommend excavation of ash as a method to overcome the geotechnical concerns raised.

Duke in support of its position, however, referred to information from a June 2015 URS Report that provided "[t]he closure of the Retired Ash Basin is in progress, with all ash being removed and transported for off-site disposal." (T 15 pp. 115-17) The Public Staff noted that this was not really a recommendation, but simply a statement that DEC had decided to move forward with excavation. The Public Staff further noted that this decision to move forward with excavation, rather than follow the original recommendations of its engineering consultants in 2014 to address the geotechnical concerns and ultimately manage all CCR materials on-site, would have resulted in the potential to reduce ash transportation costs off-site by approximately $27 million.

The Commission agrees with DEC and the Public Staff that it was appropriate to take action to address dam stability concerns at the W.S. Lee site and that ultimately the decision to excavate the ash from the IAB and the Old Ash Fill were prudent decisions. The Commission agrees with the Public Staff, however, that DEC's actions to immediately begin excavation, rather than following the recommendations of their engineering consultants at the time, resulted in much greater costs being incurred by not allowing for the full utilization of on-site options at the site. These additional costs, as calculated by Mr. Garrett, were imprudent and unreasonable. The Commission reiterates its concerns regarding the responsiveness of DEC's discovery responses, which create additional difficulties for parties seeking to validate the prudency of their actions, and that DEC has the burden of proof to demonstrate support for its selected management decisions. In circumstances where DEC does not adequately demonstrate these points, other parties may present evidence challenging the prudency of the actions taken. In this proceeding, the Public Staff has demonstrated that DEC had many motivations for its decision to excavate at W.S. Lee, but did not clearly demonstrate that the regulatory agency in South Carolina saw the excavation of the IAB and the Old Ash Fill area as an urgent concern.

With regard to the Structural Fill Area at W.S. Lee, the Commission agrees with Public Staff witness Garrett that DEC's plan to excavate and dispose of the coal ash material contained in the structural fill area at W.S. Lee is unreasonable, since the structural fill 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 has not been shown to pose any environmental concerns in its present state. (T 21 p 41) While the Commission appreciates Duke's desire to manage all ash on-site through a single lined landfill, and the act of combining the ash from the Structural Fill area with the on-site landfill may help mitigate future risk and also avoid potential future costs at a later date, there is no evidence in the record to support that the costs associated with doing this work are reasonable and prudent. DEC has not yet commenced any excavation at the Structural Fill Area, and the Commission notes that it runs the risk of any costs incurred being disallowed in future rate proceedings absent a showing that the decision to excavate and move the material is reasonable and prudent.

The Commission would also note that while DEC witness Kerin denied in cross-examination that the decision to transport ash from W.S. Lee during the timeframe agreed to under the consent agreement resulted in increased costs, shortages of equipment, and compressed the schedule of work at W.S. Lee on top of other time-sensitive closure activities underway at other DEC and DEP facilities, the record indicates otherwise. As noted in the Attorney General Fountain Cross Exhibit 6, Duke had acknowledged in January 2014 that "[t]he availability and/or lack of qualified earthwork contractors and equipment to perform construction activities across the entire fleet during the same time frame would be difficult and increase costs. This was not factored in the estimates." (T 16 pp 34-35) In addition, in the January 31, 2018 Environmental Compliance Plan Compliance Officer's Report introduced as Public Staff Kerin Rebuttal Cross Examination Exhibit 2, the report noted that "the Asheville site has shared a fleet of trucks with the W.S. Lee site. Due to extended transportation from W.S. Lee, the total ash transported for Asheville was less than the annual goal." The Commission notes that DEC and DEP have taken the approach of managing their coal ash obligations on a broad portfolio basis, with the same personnel and management overseeing the compliance schedule for both facilities. To the extent the Companies are making management decisions with regard to scheduling remedial actions, such as in the context of W.S. Lee where the DEC had significant opportunities to develop the terms of the Consent Agreement reached with SCDHEC, it is incumbent on both DEC and DEP to recognize and acknowledge the other existing obligations and schedules the Companies are operating under to avoid the unnecessary limitations on equipment, compressed schedules, and other actions that potentially result in higher costs than necessary. Instead, this portfolio approach should maximize opportunities for sharing of resources and help identify cost efficiencies. In those instances where the Commission finds that the Companies neglected to adequately consider other workloads and obligations when developing or negotiating closure schedules, the Companies bear the risk of disallowance of any of the increased costs that result from their failure to recognize these conditions.

Selection of Buck as a Beneficiation Site

Public Staff witness Moore's exception to DEC's selection of Buck as a beneficiation site was based on his opinion that DEP was already excavating the CCR material from the its Weatherspoon facility for beneficial use in the concrete industry, and that Duke Energy should have sought to establish Weatherspoon as one of the three beneficiation sites as required by G.S. 130A-309.216 in place of the DEC Buck Station. This would have allowed DEC to potentially utilize lower cost closure options at Buck instead of the use of a capital intensive carbon burnout technology. Mr. Moore testified that under Duke's original analysis, the selection of Buck as a beneficiation site increased the closure costs over the "cap in place" option by approximately $51.6 million, and that premium late was increased to approximately $91 million. (T 21 p 113)[33] Mr. Moore testified that the potential cost savings associated with would have justified additional efforts by Duke Energy to identify additional sites for beneficial reuse of ash of the additional 70,000 tons of ash from Weatherspoon.

With regard to Mr. Moore's recommendation that Duke should have selected DEP's Weatherspoon facility over Buck as a beneficiation site, Mr. Kerin testified that the products being sold from Weatherspoon are different than those that will be sold from Buck and used for different purposes. He stated that the ash from Weatherspoon was being sold to cement manufacturers to be used as raw material or aggregate in the manufacture of cement, while the beneficiated ash from Buck was being sold as a replacement for cement. Mr. Kerin also stated that the quantity of ash at the Weatherspoon site was not sufficient to support the investments necessary to beneficiate the ash, and it was in a poor geographic location with regard to the proximity to major markets for ash used in the cement industry. (T 24 p 106)

[33] These values were originally provided confidentially, but in the course of the hearing, DEC waived the confidentiality of these amounts and included the support for these cost estimates in its Duke Garrett and Moore Cross Examination Exhibit 1.

Mr. Kerin also testified that the language in G.S. 130A-309.216 that called for the "the installation and operation of an ash beneficiation project" and "produc[tion]" indicates that the General Assembly intended for Duke Energy to construct and operate technology, such as carbon burn-out plants and STAR technology, and that basic drying and screening operations such as those implemented at Weatherspoon would not qualify as beneficiation for cementitious purposes. (T 24 p 107)

DEC appears to be making the argument that the only technology or process that would comply with the statute is the STAR Technology units operated by SEFA to provide a product that is a direct replacement for Portland cement. The Commission finds that G.S, 130A-309.216(a) did not require a specific technology or process to be used, only for the "operation of an ash beneficiation project at each site capable of annually processing 300,000 tons of ash to specifications appropriate for cementitious products." Merriam-Webster's dictionary further defines cementitious as "having the properties of cement," but not requiring it to be a direct replacement for Portland cement. The Commission further notes that if the General Assembly had desired that only a single technology be selected, they could have specified the technology in statute (see, e.g., the use of the phrase "carbon burnout plants" in G.S. 130-392.205(a)).

The general premise of Duke's argument that it could not sign long-term commitments for all 300,000 tons from Weatherspoon is also flawed. Under Duke's analysis, since they could not sign long-term commitments for an additional

70,000 tons of ash at Weatherspoon, they instead selected an entirely different site for beneficiation, which required them to identify purchasers for an additional 300,000 tons per year of cementitious products. While the products generated by each of the technologies varied, and the prices that they would have commanded in the market would have been different, both resulted in products that are currently being sold into the cement market in different parts of the DEC and DEP service territories. The Commission acknowledges that there may have been additional cost associated with finding buyers for the remaining 70,000 tons from Weatherspoon, even some transportation costs to additional markets, the significant premium that resulted from the selection of Buck provided significant opportunities to evaluate this market, which Duke declined to do.

The Public Staff also noted concern that Duke's selection of Buck for cementitious beneficiation was driven the Company's goal to reach a settlement with environmental groups regarding pending litigation at the Buck station. They noted that Duke publicly announced at the time Buck was selected that:

> Duke Energy's plan to remove and recycle ash from the Buck station also addresses the issues in the federal lawsuit brought by the Southern Environmental Law Center, SELC. Both Duke and SELC will make the necessary court filings to dismiss that case." (T 15 p 108)

The Public Staff lastly noted that Buck had not previously been identified as a cost effective beneficiation location, as compared to other Duke facilities with larger quantities of ash. (T 15 pp 101-04) Despite the Buck facility's smaller quantity of ash relative to other Duke facilities, however, DEC anticipates needing to seek multiple statutory waivers under G.S. 130A-309.215 from the Secretary of Environmental Quality for extensions of time in order to fully remediate the site. In comparison, the Weatherspoon facility could have been fully closed within the timeframe called for in G.S. 130A-309.216.

The Commission agrees with Public Staff witness Moore and DEC witness Kerin that Duke Energy should continue to make commercially reasonable efforts to identify additional sites for cost-effective beneficial reuse of ash in order to reduce closure costs for customers. The Weatherspoon facility sufficiently met the requirements of G.S. 130A-309.215 and DEC should therefore have pursued that site as the third beneficiation site required by statute. The Commission therefore disallows the $10 million that DEC has unreasonably incurred for the cementitious beneficiation project at Buck. To the extend DEC seeks to continue to move forward with excavation and beneficiation of the coal ash materials at Buck using STAR technology for which it is already under contract, the Commission recognizes that this decision was made in order to resolve the lawsuit brought by SELC or for other purposes not specifically designed to comply with CAMA.

Other Determinations

The Commission notes that DEC is not required to submit proposed closure plans for the impoundments at Allen, Belews Creek, Cliffside, and Marshall to DEQ for review and approval until December 31, 2019, pursuant to G.S. 130A-309.214(a)(2) and (3). Therefore, a prudence review of these closure plans would be premature at this time. As such, the Commission does not take any position with regard to the closure plans at those facilities at this time, since the current plans are preliminary in nature and have not yet been approved by the appropriate environmental regulatory agencies. Mr. Kerin testified that the bulk of the costs incurred to date by the Company have been related to the provision of alternative water supplies, along with investigating remediation options and developing draft closure plans. (T 14 pp 221-23; T 16 pp 51-52) The Commission finds, however, that to the extent the Company begins to incur costs associated with a closure option that has not received regulatory approval, the Company faces the risk of disallowance of those expenditures are found to be imprudent based on the ultimate closure options that are selected or mandated.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 59-74

The evidence supporting these findings of fact and conclusions is contained in the Application, 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 and 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.

DEC has relied upon coal-fired power plants throughout its history, and depends upon coal-fired generation today. Coal ash, also known as coal combustion residuals, or CCRs, is a by-product of coal-fired generation. Since the 1950s, standard industry practice, at least in the Southeast, has been to deposit coal ash in coal ash basins, and such basins were constructed and were or are 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 and began moving forward on comprehensive regulation of CCRs approximately 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 its Coal Ash Management Act (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 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, consistent with the Commission's Orders in Docket No. E-7, Sub 723, deferred the impacts of its GAAP-mandated ARO accounting. The Company 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.[34] 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 $200.6 million per year in annual coal ash basin closure spend. This amount is based upon DEC's calculation of the NC retail jurisdiction portion of the test period 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

[34] This amount excludes any fines, penalties and other unrecoverable costs incurred by the Company, and also includes carrying costs through April 2018, calculated in the manner set forth in the Company's rebuttal filing.

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 $200.6 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 the Company's next rate 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 arguments raised by some 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.

Summary of the Evidence

DEC DIRECT TESTIMONY

In their direct testimony, DEC's witnesses stated that coal ash costs included in the Company's rate request were incurred to comply with newly enacted laws and regulations. Specifically, the DEC witnesses stated that the Company's ash basins are being closed pursuant to the U.S. Environmental Protection Agency "Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities; Final Rule" published in the Federal Register Vol. 80, No. 74, on April 15, 2015, (CCR Rule) and the North

Carolina Coal Ash Management Act (CAMA) , Session Law 2014-122, and subsequent amending legislation; the Mountain Energy Act, Session Law 2015-110, and the Drinking Water Protection/Coal Ash Cleanup Act, Session Law 2016-95.

DEC witness Fountain, President of DEC's North Carolina operations, summarized the Company's request for a five-year amortization with return, to recover what he characterized as costs to comply with "emerging state and federal laws and regulations regarding the management and closure of coal ash basins," incurred from January 1, 2015, through November 30, 2017, and also an additional annual rate recovery for anticipated ongoing expenses related to coal ash closures and compliance. (T 6 p 169)

In her pre-filed direct testimony, DEC witness McManeus explained the amounts requested by DEC:

> The compliance costs are based on actuals as of the end of the Test Period plus a projection through November 30, 2017. The total system spend on coal ash pond closure costs during this period for DE Carolinas is $677.9 million ($170.2 million in 2015, $287.3 million in 2016, and $220.4 million in the 2017 projected period). After applying allocations factors, and incorporating the return on the deferred costs, the expected deferred balance as of November 30, 2017, on a North Carolina retail basis is $524.0 million. Over the 5-year amortization period, the annual amortization expense is $105.1 million, including regulatory fee impacts. When added together with the net of tax return on the unamortized balance of $29.9 million, the total revenue requirement requested in this case for deferred coal ash pond closure costs is $135.0 million.
>
> (T 6 pp 259-60)

Of this amount, a portion would be deducted from rate case recovery if allowed to be recovered through the annual fuel rider:

> Of the $524.0 million expected deferred balance, $85.9 million ($73.1 million of spend and $12.8 million of return) is related to 2017 beneficial reuse projected costs. While these amounts are included in this request, we believe these costs are more appropriately recovered through the annual fuel rider as discussed by Witness McGee. If the Commission approves the fuel rider treatment requested by Witness McGee, DE Carolinas would remove $85.9 million from the deferred balance in this adjustment.
>
> (T 6 p 260)

In addition, witness McManeus proposed to include in rates an ongoing expense amount for future coal ash costs, called a “run rate,” which would ultimately be trued up to actual expenditures. She explained:

> The expected ongoing level of O&M is based on the Company's actual spend on coal ash during the Test Period, which was $288.2 million on a system basis, or $201.3 million on a North Carolina retail basis . . . . The Company is also requesting 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 . . . . In addition, since the amortization proposed in Adjustment 18 only includes deferred costs through November 30, 2017, the Company requests to defer to the regulatory asset the coal ash spend incurred after that date, but before new rates from this proceeding are effective.
>
> (T 6 pp 260-61)

DEC witness Wright testified that costs associated with environmental compliance are recoverable in rates. (T 12 p 123) He noted that the DEC coal plants have been used and useful in providing electric service, so ash disposal costs associated with the plants should receive a return on the deferred balance.

(T 12 pp 124-25) Like other Company witnesses, witness Wright distinguished fines and penalties as costs that are appropriately excluded from rate recovery. (T 12 p 130) According to witness Wright, the coal ash costs for which the Company seeks recovery in the present case are related to new coal ash disposal regulations. (T 12 p 138)

Witness Wright opined that "the Company historically has complied with all coal ash disposal regulations . . . ." (T 12 p 144) He submitted that the coal ash costs in the present case are a "used and useful" utility cost, proper for inclusion in rate base. (Id.) Witness Wright maintained that the DEC coal ash costs should be deemed prudently incurred, and allowed to be recovered through an amortization with a return, similar to what the Public Staff recommended and the Commission approved in the 2016 DNCP Rate Case. (T 12 pp 146-47)

Most of the operational details of DEC's coal ash expenditures were described by Company witness Kerin. He stated that DEC was seeking recovery of CCR compliance costs, and that "[s]ince the early 1900s, DE Carolinas has disposed of CCRs in compliance with then current regulations and industry practices." (T 14 p 99) He noted that fines and penalties related to coal ash management had been excluded from the Company's rate request. (T 14 p 101)

Mr. Kerin described the Company's coal-fired electric generation resources, the Company's past CCR storage and disposal practices, and the history of applicable regulations for coal ash management. He generally discussed the requirements of the CCR Rule, CAMA, and consent or settlement agreements and orders affecting closure of ash basins, and other aspects of CCR management. (See T 14 pp 99-136) His exhibits included the amount of ash and history of ash disposal for each plant, initial closure plans for ash basins, a breakdown of expenditures in 2015-2016 for coal ash compliance at each plant site and an estimate of expenditures for January through November 2017, and a plant-by-plant summary of ash management cash flows for ARO purposes. Mr. Kerin testified that the coal ash costs submitted for recovery in the present case were prudent and reasonable. (T 14 p 135)

In supplemental and rebuttal testimony (as impacted by the agreement in the Partial Stipulation regarding rate of return), witness McManeus removed certain costs improperly allocated to NC retail customers and adjusted the dollar amounts to reflect actual costs incurred through December 31, 2017, resulting in a proposed annual amortization expense for deferred coal ash costs of $113.3 million. (Maness Late-Filed Exhibit) Witness McManeus also accepted two coal ash-related adjustments recommended by Public Staff witness Maness. The first is the addition of a return on the deferred balance of coal ash costs through the date of expected new rates in this proceeding. The second is the calculation of the return using a mid-month convention. (T 6 p 314) However, as described later, there remain relatively small differences between the return calculations of the Company and the Public Staff.

INTERVENOR TESTIMONY

Sierra Club witness Quarles testified that the utility industry was aware since at least the mid-1970s that disposal of CCRs in unlined basins within close proximity to groundwater was risky. (T 6 p 22) He opined that construction of unlined disposal units after that time was unreasonable given scientific knowledge regarding the mobility of CCR constituents and their harmful impact on groundwater and the increasing prevalence of lined disposal units due to these risks. (Id.) Witness Quarles further testified that DEC's plans for cap-in-place closure of the ash basins at the Allen and Marshall plants would result in continuing contamination of down-gradient groundwater. (T 6 pp 24, 27) He opined that the Company's closure plans for those two plants would violate the federal CCR Rule by not sufficiently protecting groundwater from migration of coal ash constituents. (Id.) Witness Quarles requested that the Commission make findings consistent with his testimony.

CUCA witness O'Donnell maintained that CAMA was the direct result of Duke Energy mismanagement that caused the Dan River spill, and therefore costs resulting from CAMA should be excluded from rates. (T 18 p 60) He cited Duke Energy's guilty pleas for criminal violations of the Clean Water Act in connection with the Dan River spill as evidence of mismanagement. However, he stated that coal ash cleanup costs resulting from the CCR Rule were incurred in the "normal course of business" and therefore should be recovered in rates. (T 18 pp 59-60)

Witness O'Donnell then estimated the amount of CAMA-based coal ash cleanup costs, over and above the costs to comply with the CCR Rule, by comparing the coal ash AROs of DEC and DEP to other electric utilities across the country that are not subject to CAMA-type cleanup requirements. (T 18 pp 62-63) He further refined that analysis by calculating the coal ash ARO cost per megawatt hour (MWh) of coal generation. (T 18 p 64) According to this calculation, DEC's coal ash ARO cleanup cost per MWh of generation is two-times greater than the average cost for "neighboring" utilities. (T 18 p 66) Witness O'Donnell noted that the current EPA is reconsidering the CCR Rule, so there is a possibility that costs to comply with the CCR Rule may be further reduced or even eliminated. (T 18 p 67)

Witness O'Donnell recommended that the Commission disallow 75% of the coal ash costs submitted for recovery in the present case. (T 18 p 68) He observed that, even with this disallowance, North Carolina customers would still pay more for coal ash disposal than customers in neighboring states. (Id.) He also requested that coal ash costs be listed as a separate line item on customers' bills if his recommended coal ash disallowance is not adopted by the Commission. (T 18 pp 68-69)

AGO witness Wittliff testified that the Company's imprudent coal ash management justifies the disallowance of costs of coal ash-related environmental remediation and ash impoundment closure mandated by laws and regulations enacted largely as a result of the Company's mismanagement . (T 11 pp 240-41)

Like CUCA witness O'Donnell, witness Wittliff opined that the Dan River spill was the catalyst for the enactment of CAMA. (T 11 pp 248-50) Witness Wittliff compared the provisions of the CCR Rule and CAMA and concluded that CAMA is considerably more restrictive than the CCR Rule. (T 11 p 250) In support of his conclusion, witness Wittliff noted that while the CCR Rule only requires closure for basins that do not meet various safety and environmental criteria, with an emphasis on stability evaluation, CAMA requires closure of any impoundment not rated "low risk."[35] (T 11 pp 250-51) Witness Wittliff further noted that the CCR Rule allows cap-in-place closure for a wider range of impoundments than CAMA, which only permits cap-in-place at "low risk" sites. (T 11 p 251)

Witness Wittliff asserted that DEC had not kept pace with the rest of the utility industry in terms of its management of coal ash. (T 11 p 255) He noted that the EPA, in the February 5, 1981, Federal Register, opined that all landfills will leak eventually, but that unlined landfills and impoundments will leak sooner and more catastrophically than lined ones. (T 11 p 258) Witness Wittliff noted that, despite this widely published information, and the requirements contained in its NPDES permits, the Company failed to take any steps to stop leaks and seeps from its unlined impoundments until lawsuits were filed in 2013 and the Dan River spill in the following year. (T 11 pp 256, 258) Witness Wittliff also reviewed information, including Duke Energy's SEC 10-K filings for the years 2008 through 2016, which

[35] Witness Wittliff noted that, as of the time of his testimony, none of the Company's impoundments had been classified as "low risk." (T 11, p 251)

in his opinion showed that “the Company was well aware that the trend in coal ash management and regulation was toward storing coal ash in lined impoundments, to avoid groundwater contamination.” (T 11 p 236) He further opined that, despite its knowledge of this trend, the Company continued to store coal ash in unlined surface impoundments, landfills, and ash stack out areas up to 2017. (T 11 p 252)

Witness Wittliff also asserted that DEC had not met environmental compliance requirements regarding coal ash management, disposal, and storage. (T 11 p 265) He noted that the Company’s failure to comply with such requirements was the subject of federal criminal charges to which the Company pled guilty in 2015, as well as complaints brought in state courts, and notices of violation issued by the North Carolina Department of Environmental Quality (DEQ). (T 11 pp 265-67)

Public Staff witnesses Garrett and Moore recommended disallowances of particular coal ash costs. Their recommendations are discussed elsewhere in this Order. In addition, Public Staff witness Maness proposed an “equitable sharing” of the remaining coal ash costs, and witness Lucas recommended against allowing recovery of costs related to the disposal of coal ash at Brickhaven through the fuel adjustment clause, as addressed in more detail elsewhere in this Order.

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. (T 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. (T 26 pp 721-22) This is essentially the approach recommended by CUCA and the AGO. 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. (T 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. (T 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. (T 26 pp 723-34) At the same time, 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. (T 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). (T 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. (T 26 pp 727-28)

Witness Junis noted that DEC has removed the costs listed in item (3) above from its rate request. (T 26 p 728) Thus, the regulatory treatment of those costs is not in dispute. The disallowances recommended by 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. (T 26 pp 730-31) Witness Junis asserted that there is compelling evidence of the environmental violations on which these legal actions were based. (T 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. (T 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. (T 26 p 734) Witness Junis noted that there could be additional costs in this category in the future. (T 26 p 732)

The final category for disallowance is based on an "equitable sharing" of all coal ash-related costs not otherwise disallowed. (T 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." (T 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. (T 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. (T 26 pp 739-40) Witness Junis asserted that the numerous lawsuits regarding DEC's non-compliance with G.S. 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. (T 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. (T 26 pp 741-42)

Witness Junis refuted DEC witness Kerin's assertion in his testimony that the EPA's 2015 Effluent Limitations Guidelines Rule forced DEC to convert its coal-fired plants to dry ash handling. (T 2, 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. (T 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. (T 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." (T 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. (T 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. (T 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. (T 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. (T 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:

1. 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. (T 22 pp 65-66, 147, 153-54)

2. 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.

3. 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. (T 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%. (T 22 pp 149-50)

4. 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. (T 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. (T 22 p 149)

5. 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. (T 22 pp 70-85, 153-54)

6. 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. (T 22 pp 70-85, 153-54, 162)

7. 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.

DEC REBUTTAL TESTIMONY

DEC witness Fountain provided an overview of the Company's rebuttal case, including a summary of the DEC response to intervenor direct testimony on coal ash cost recovery issues. He disputed the assertions of several intervenors that CAMA is more restrictive and expensive to comply with than the federal CCR Rule. (T 6 p 202)

Witness McManeus opposed the Public Staff's recommendation to remove from the rate request an estimated amount for ongoing environmental costs (the "run rate"). (T 6 p 315) She noted that the main reason offered by witness Maness for his recommendation was that the run rate would make future equitable sharing of coal ash costs much harder to achieve and indicated that the Company opposed any sharing of such costs for the reasons stated by its witness Wright. Witness McManeus noted that coal ash basin closure costs would be recurring in the future, are equivalent to the Company's test year spend, and are therefore the same as other ongoing and recurring expenses incurred in the test year and carried forward into rates, such as vegetation management. (T 6 p 316) Witness McManeus noted that the Company would also agree with the implementation of a rider as an alternative mechanism for recovering ongoing costs of coal ash basin closure, as suggested by Chairman Finley during the questioning of DEP witness Bateman during the expert testimony hearing in Docket No. E-2, Sub 1142. (Id.)

Finally, witness McManeus stated that the Commission should allow the Company to earn a return on the deferred coal ash balance because the costs of compliance have been advanced by investors and, therefore, the Company should be allowed to earn a return "during the period for which the Company will amortize and collect these amounts from its customers" because the Company will continue to incur the costs of financing the uncollected balance of funds. (T 6 p 317)

DEC witness Wright in rebuttal testimony took issue with the Public Staff's equitable sharing recommendation. (T 12 errata p 156-4) He characterized witness Junis' assignment of 51% of the coal ash costs to DEC as a "split the baby" approach which he warned "could be seen as arbitrary and capricious." (T 12 errata p 156-5) Witness Wright opined that the Commission could consider equity in specific circumstances and at specific stages of review, including where the costs at issue are not used and useful. (T 12 errata p 156-5)

Witness Wright noted that Witness Junis' equitable sharing recommendation was not based on the prudency standard, and stated he found this surprising given that both witness Junis and Public Staff Maness supported the disallowances recommended by Public Staff witnesses Garrett and Moore, which they arrived at through the application of a prudency standard. (T 12 errata pp 156-5-6)

Regarding witness Junis' testimony that the Company has a responsibility to avoid seeps, witness Wright indicated that "the fact that seeps occurred, and continue to occur, is simply a circumstance expected in earthen impoundments . . . ." (T 12 errata p 156-9) He noted that the Company "began discussions with [DEQ] regarding the permitting of seeps" when the Environmental Protection Agency first instructed permitting authorities to consider the potential impacts of seeps in 2010. Based on this information and on the rebuttal testimony of Company witness Wells, witness Wright stated he could not conclude that the

Company had acted improperly or imprudently in addressing seeps. (T 12 errata pp 156-8-9)

Witness Wright acknowledged that the Company has a responsibility to avoid exceedances of groundwater standards pursuant to North Carolina's 2L groundwater rule[36]. (T 12 errata p 156-9) However, he also stated that it was expected that water would leach coal ash constituents from impoundments, and that these constituents would be carried through the soil. (Id.) He also stated that exceedances were not unexpected, and that their occurrence was not evidence of any deficiency in the Company's construction of its facilities. (T 12 errata p 156-10) Rather, according to witness Wright, the occurrence of exceedances "simply means that the naturally occurring plume of water from leaching out of the coal ash pond carrying the leachates has not reached the facility's monitoring wells." (Id.)

Witness Wright testified that the Public Staff's equitable sharing proposal was inconsistent with the Public Staff's cost recovery recommendations in the 2016 DNCP rate case in which the Public Staff had not opposed full recovery of coal ash costs. (T 12 errata p 156-11) He noted that a federal court had determined that there were violations of the federal Clean Water Act at a DNCP plant. (Id.) Witness Wright also noted that DNCP had initiated groundwater monitoring in 2002 and ultimately accepted a corrective action plan for one of its Chesapeake Energy Center sites. (T 12 errata pp 156-12-13) Citing these two

[36] Title 15A, North Carolina Administrative Code, subchapter 02L.

examples, witness Wright disagreed with witness Junis' testimony that the volume of environmental regulatory action against DNCP was significantly less than that against the Company. (Id.)

Witness Wright rejected the comparison of regulatory treatment for coal ash costs to that of abandoned nuclear plant costs. (T 12 errata p 156-15) He argued that the abandoned nuclear plants were never used and useful, but that CCR repositories were used and useful and therefore coal ash disposal costs were used and useful, making it appropriate to include in rates a return on those costs. (T 12 errata pp 156-15-16) Witness Wright distinguished manufactured gas plant costs based on a "timing difference" between the use of those facilities and the recovery of their environmental clean-up costs, which he argued was different from the timing applicable to coal ash costs. (T 12 errata pp 156-16-17) He also stated that DEC or its predecessors had always owned the coal ash basins, but the manufactured gas plants had changed ownership before clean-up costs were incurred by the regulated gas utilities. (T 12 errata p 156-17)

Witness Wright characterized witness Maness' position as being that an equitable sharing of coal ash costs was appropriate just because the costs were extremely large. He argued this approach was outside any regulatory policy or law, and would drive up the perceived risk of utilities. (T 12 errata pp 156-21-22)

Witness Wright then stated his understanding and criticism of some of the reasons given by witness Junis for an equitable sharing. He disagreed with any claim by witness Junis that Duke Energy "caused or substantially caused" CAMA and the CCR Rule. (T 12 errata p 156-23) He argued that the Dan River spill only impacted the timing of the adoption of CAMA, and did not agree that the spill led to modifications in the final CCR Rule or resulted in CAMA being stricter than it would have been had the spill not occurred. (Id.) He pointed out that other states have enacted state-specific coal ash laws or rules just as North Carolina did. (T 12 errata pp 156-25-26) He also maintained that the CCR Rule and CAMA were not meant to be punitive, so costs incurred under those requirements are recoverable. (T 12 errata p 156-25)

Witness Wright disagreed with witness Junis' recommended disallowance of approximately $2.1 million in litigation costs. (T 12 errata p 156-31) He observed that fines, penalties, and fees related to the Dan River plant were appropriately excluded by the Company from its rate request, and noted that he did not oppose exclusion of legal fees where DEC has admitted liability or in certain instances in which the Company has been adjudicated as liable. (T 12 errata pp 156-31-32) However, he characterized witness Junis' approach as excluding all costs of defending lawsuits, whether or not there has been an admission or determination of liability. (T 12 errata p 156-32) Witness Wright disagreed with witness Junis' recommendation that the Commission disallow costs for civil cases where there had not been an admission or adjudication of liability, but where there was compelling evidence of environmental violations. (Id.) He stated, "Mr. Junis' subjective view of what he finds to be 'compelling evidence of environmental violations' is not, and logically cannot be, a proper standard of regulatory cost recovery." (Id.)

He said that witness Junis in effect advocated the position that legal defense costs were *per se* imprudent, which he stated was equivalent to arguing the Company should never defend itself or settle cases. (Id.) Witness Wright disagreed with witness Junis' reliance on the Glendale Water case (State ex rel. Utils. Comm'n v. Public Staff, 317 N.C. 26, 343 S.E.2d 898 (1986)) for his recommendation to disallow legal fees. (T 12 errata p 156-33) He asserted that the violation involved in Glendale Water was different in nature, and that Glendale Water involved what the Court determined were avoidable legal fees, whereas the legal fees witness Junis recommended for disallowance were not avoidable due to the citizen suit option exercised in the cases against DEC. (Id.) Witness Wright also disagreed with witness Junis' contention that settlements payments made to DEQ where DEC did not admit liability were persuasive evidence of liability.[37] He noted that DEC did not admit any liability in its settlements of environmental lawsuits over coal ash contamination, and that settlements should be encouraged as a matter of policy. (T 12 p 156-34)

Witness Wright indicated that witness Junis was unreasonable in saying shareholders should bear remediation costs above what is necessary to comply

[37] In their stipulation filed March 14, 2018, DEC and the Public Staff agreed to strike from witness Junis' direct testimony the following sentence located at page 718 of transcript volume 26: "In addition, it is my opinion that DEC's agreement to pay $5.98 million to settle the DEQ penalty proceeding regarding NPDES and other surface water violations at the Dan River plant, and an additional $16,250 corresponding to five seeps identified in the March 4, 2016 NOV, is persuasive evidence of environmental violations notwithstanding DEC's denial of liability."

with CAMA at Belews Creek, while at the same time expecting DEC to fully comply with groundwater standards. (T 12 errata pp 156-36-38)

Witness Wright also argued against witness Maness' recommendation of provisional cost recovery. (T 12 errata p 39) Witness Wright stated that provisional recovery of costs is problematic both because it appears to be retroactive ratemaking, and because utilities are required to make decisions based on the best available information in their possession at the time and should not, therefore, be subject to hindsight review. (T 12 pp 156-39-40)

Finally, witness Wright disagreed with the positions of CUCA witness O'Donnell and AGO witness Wittliff. Witness Wright argued that, in concluding that DEC's coal ash remediation costs are higher than that of any other utility, witness O'Donnell failed to consider the fact that DEC is further ahead than other utilities in the mitigation of its coal ash ponds. (T 12 errata p 156-41) He also asserted that there were errors in witness O'Donnell's data regarding the coal ash mitigation costs of other utilities. (T 12 errata pp 156-41-42) With respect to witness Wittliff, witness Wright disagreed that the Dan River spill was the impetus for CAMA in any respect other than timing. (T 12 errata p 156-43) He also disagreed with witness Wittliff's contention that CAMA is a punitive statute. (Id.) In addition, witness Wright pointed out that witness Wittliff did not identify any specific coal ash remediation costs as being unreasonable or imprudent. (T 12 errata pp 156-43-44)

Witness Kerin's rebuttal primarily addressed the position of Public Staff witnesses Garrett and Moore, which is discussed elsewhere in this Order. (T 24 p 90) However he also addressed Public Staff witness Junis' recommendation that the cost of extraction wells and groundwater treatment at Belews Creek be disallowed and argued that the wells would have been installed to comply with CAMA even in the absence of the Sutton settlement agreement. (T 24 p 117) Regarding witness Junis' recommendation that the cost of the SeaHAWK selenium removal equipment installed at the Riverbend site be disallowed, witness Kerin asserted that the equipment "mitigate[d] against the risk that selenium limits in Riverbend's NPDES permit could not be achieved through physical/chemical water treatment methods." (Id.) He stated that DEC had determined at the beginning of the dewatering operation at Riverbend that there was a "high probability" that the SeaHAWK equipment would be required and that, in November of 2017, the Company "came close" to putting the system in operation after selenium levels rose. (T 24 p 118) During cross-examination, witness Kerin stated that the SeaHAWK equipment had been placed into operation in February 2018, but he did not indicate if it continued to be in operation after February, or if the operation of that equipment was necessary to comply with standards for selenium. (T 24 pp 176-77)

Witness Kerin disputed AGO witness Wittliff's contentions that DEC had failed to keep up with the industry standard in its coal ash management practices, and that DEC should have constructed new lined impoundments for the storage of coal ash instead of expanding existing unlined impoundments. (T 24 pp 119-21)

Witness Kerin asserted that any such action would not have been in keeping with then current industry standard practices, and that the Company would have had to risk disallowance of the associated costs. (T 24 p 121) He further noted that the Company would have been required to manage both the old, unlined impoundments as well as the new ones. (Id.) Regarding witness Wittliff's criticism of DEC's dam management practices, witness Kerin cited the Company's five-year dam safety inspections dating back to the 1970s, which he argued showed "no instance in which the Company failed to act upon a major dam safety issue." (T 24 p 123)

With respect to CUCA witness O'Donnell, witness Kerin asserted that his recommended disallowance of 75% of coal ash ARO amounts was based on an inadequate comparison with coal ash AROs for other utilities. In particular, witness Kerin listed numerous factors affecting such AROs, which were not analyzed by witness O'Donnell and therefore, in his opinion, reflect a weakness in witness O'Donnell's analysis and recommendation. (T 24 pp 125-28)

Finally, witness Kerin disagreed with Sierra Club witness Quarles' contention that DEC was unreasonable in continuing to operate unlined coal ash basins after the 1980s. (T 24 pp 128-29) He stated that, although there was an increase in the number of lined basins in the 1970s and 1980s, lined basins were still in the minority, which supported his contention that unlined basins were still the industry standard during that period. (T 24 pp 128-29) Witness Kerin further disagreed with witness Quarles' assertion that costs of construction and closure/post-closure costs were higher than the cost of lined landfills because witness Quarles failed to consider additional costs such as conversion to dry ash handling and rerouting other wastewater that would be involved in conversion to lined landfills. (T 24 p 129) Witness Kerin also testified that DEC sold coal ash for reuse from the Marshall and Belews Creek plants in the 1980s to counter what was characterized as witness Wittliff's testimony to the contrary. (T 24 p 129)

In his rebuttal testimony, DEC witness Wells testified that the Company had taken appropriate steps to manage groundwater and seeps at its ash basins, contrary to witness Junis' negative characterization of environmental compliance. (T 24 p 224) He asserted that witnesses Junis, Wittliff, and Quarles misrepresented the industry standard practices for coal ash management in their testimony, and stated that DEC's use of unlined coal ash impoundments was "reasonable and consistent with the approach employed across the power industry at the times when the basins were built." (T 24 p 225) Witness Wells argued that witness Junis was incorrect when he testified that each individual violation of a groundwater standard is a separate violation of the 2L groundwater rules. (Id.)

Witness Wells disagreed with witness Junis' testimony that exceedances of groundwater standards at the Company's coal ash sites are indicative of mismanagement by the Company. (T 24 p 227) He argued that groundwater exceedances at or beyond the compliance boundaries were a "function of where these sites are on the timeline of groundwater assessment and corrective action under modern laws that have changed the way that unlined basins are viewed."

(T 24 p 227) Witness Wells asserted that DEC had done everything required of it to comply with the 2L groundwater rules and CAMA "to address groundwater impacts as they have been identified." (Id.)

Witness Wells maintained that the Company was reasonable in using unlined basins to treat ash transport water. (T 24 p 228) He noted that the Company's ash basins were constructed between 1956 and 1985, and that unlined basins were the main method of treating ash transport water during this period. (Id.) He also stated that the 2L groundwater rules did not require monitoring of groundwater, but that the Company had nonetheless started monitoring groundwater around the ash basin at its Allen plant, and conducting leachate tests at its other sites to evaluate the concentration of constituents and whether they would reach the groundwater. (T 24 pp 229-30) Witness Wells discussed a study published by Arthur D Little in 1982 which concluded that soil attenuation was likely preventing arsenic from migrating from the ash basin at the Allen plant, and an internal report by the Company from 1984 which concluded that wet disposal of coal ash was not significantly impacting the groundwater at any of the Company's coal ash sites. (Id.) Witness Wells noted that groundwater monitoring conducted at the Company's Belews Creek, Marshall, Dan River, Allen, and Riverbend beginning in 1989 showed exceedances of various constituents, but he stated that these exceedances did not show a pattern of ash constituents migrating from landfills or that the coal ash basins were otherwise "materially impacting" the groundwater. (T 24 pp 230-31)

Witness Wells asserted that papers cited by witnesses Junis, Wittliff, and Quarles in their testimony did not condemn the use of unlined basins for the storage of coal ash but, rather, "highlight evolving state of knowledge regarding the risks and best practices associated with coal ash disposal management." (T 24 p 232) Witness Wells stated that, if DEC had used lined landfills initially, or removed ash from unlined basins when groundwater concerns first arose, then the Company would have been using unproven technology without regard to cost and without legal obligation. (T 24 p 233)

Witness Wells disputed witness Junis' testimony that DEC did not engage in comprehensive groundwater monitoring and remediation until the threat of litigation, the Dan River spill, and CAMA occurred. (T 24 p 234) He noted that witness Junis' Exhibit 25 showed that the Company had 383 monitoring wells at its coal ash sites, and questioned why witness Junis did not consider this level of monitoring "comprehensive." (Id.) He further noted that, prior to the institution of legal action, the Dan River spill, or the enactment of CAMA, the Company began installing its monitoring wells in 2006 and worked with DEQ to relocate wells and comply with a 2011 DEQ policy regarding the steps to be taken after identification of a groundwater exceedance. (T 24 pp 235-36)

Witness Wells testified that state groundwater regulations and DEQ practices are intended to achieve corrective action as opposed to enforcement and are, therefore, not meant to be used to deny cost recovery in regulatory proceedings. (T 24 pp 237-38) To this point, he argued that witness Junis "ignore[d] the iterative nature of site characterization" in his description of groundwater violations under the 2L rules. (T 24 p 239) Witness Wells asserted that a single activity could result in a plume at a coal ash basin, which could result in multiple violations of groundwater standards, but which "does not result in multiple violations of the prohibition in 15A NCAC 2L.0103(d)." He implied that this distinction contradicts witness Junis' contention that the volume of DEC's exceedances is indicative of the extent of its environmental violations. (T 24 p 240) He also argued that the groundwater exceedance data presented by witness Junis "[did] not signify the number of groundwater violations, but rather the thoroughness of the evaluation."

In response to the Public Staff's recommendation that the costs of groundwater extraction and treatment at the Belews Creek plant be disallowed, Witness Wells disputed that groundwater exceedances at the plant were the result of mismanagement. (T 24 p 241) Instead, he stated that the extraction and treatment work would have been required of DEC "under the normal course as part of groundwater corrective action under the CCR Rule and CAMA even without the settlement [of the Sutton Notice of Violation from DEQ]." (Id.)

Witness Wells did not agree with what he characterized as witness Junis' assertion that DEC was imprudent based on the amount of litigation regarding the ash basins. (T 24 p 242) He attributed the litigation to non-governmental organizations. (T 24 p 244) Witness Wells also testified that, according to witness Junis, any exceedance or violation, no matter how minor or far removed, should lead to disallowance of costs. (Id.) He argued that the corrective action provisions in the 2L rules show that exceedances were expected from facilities that were built before liners were required, and that such exceedances are to be addressed in a measured manner rather than classified as mismanagement. (T 24 p 245)

Witness Wells discussed seeps at length. (T 24 pp 246-53) He noted that seeps are the movement of liquid through earthen dams, and that some seeps exhibit low or no flow volume and may be transient. (T 24 pp 246-47) He stated that DEC's engineered seeps that discharge to surface waters were included in the Company's 2014 NPDES permit applications. (T 24 p 246)

Witness Wells testified that DEQ has long been aware of the existence of seeps, but it did not consider seeps to be a priority in earlier years. (T 24 p 247) He stated that closure of ash basins would be one way to correct seeps, but that closure would not necessarily be required as a result of seeps, and that any suggestion by witness Junis to the contrary was incorrect. (T 24 pp 149-50) Witness Wells indicated that the Company had entered into a special order by consent (SOC) with DEQ to address seeps at Allen, Marshall, and Cliffside, which included an accelerated schedule for dewatering the basins at the plants.[38] (T 24 p 252)

[38] A public hearing before the North Carolina Environmental Management Commission took place on March 8, 2018. Following the hearing, the EMC recommended that DEQ strike from the SOC language indicating that DEC's payment of penalties pursuant to the SOC "'is not an admission or result of any wrongdoing or evidence of mismanagement, negligence, imprudence, or final determination of violations of laws, rules or standards.'" (T 26, pp 25-27)

Witness Wells challenged witness Junis' testimony that DEC's failure to comply with environmental regulations was a contributing factor to the adoption of both the CCR Rule and CAMA. (T 24 p 254) He stated that the EPA had engaged in two decades of study before issuing the proposed CCR Rule in 2010, and had identified groundwater damage from coal ash impoundments across the country to justify the CCR Rule, but had not identified damage from DEC other than a single surface water discharge that had been resolved. (T 24 p 255)

In sum, the rebuttal testimony of the Company's witnesses downplayed the extent and evidence of environmental violations raised by witness Junis and other intervenor witnesses. The Company witnesses emphasized that coal ash costs in the present case were prudently and reasonably incurred to comply with environmental laws; that DEC's use of unlined ash basins was consistent with industry practice at the time; and that DEC had complied with evolving regulations on coal ash disposal. The rebuttal witnesses argued there were no good policy or legal reasons for the Public Staff's or other intervenors' recommendations as to disallowances and equitable sharing.

Commission Determinations

The Commission has reviewed with care the evidence on the issue of CCR remediation cost recovery and the arguments and contentions of the parties. The

Commission rejects full recovery advocated by DEC, and some of the disallowances advocated by other parties.

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). (T 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.

Regarding the seven adjustments to the Company's proposed recovery of coal ash costs recommended by Public Staff witness Maness in his initial direct testimony, the Commission has weighed these adjustments and competing evidence to reach the following conclusions:

1. Incorporation of the adjustments to reflect a prudent and reasonable level of coal ash expenditures as recommended by Public Staff witnesses Moore, Garrett, and Junis. The Commission concludes these adjustments are reasonable, as discussed elsewhere in this Evidence and Conclusions section.

2. Adjustments 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 the South Carolina retail; and (b) 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. (See T 6 pp 259, 313-14; T 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. (T 22 pp 66-67) Regarding the allocation factor, the Company recommended the demand-related factor (see T 6 p 314; T 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 (T 22 pp 67-68). The Commission agrees with 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.

3. With regard to the addition of a return on deferred coal ash expenditures from December 2017 through April 2018, DEC agreed with this adjustment (T 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.

4. Mid-month cash flow convention. Witness McManeus accepted this adjustment (T 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.

5. Amortization of the balance of deferred coal ash expenditures over a 25-year period, rather than the 5-year period proposed by the Company. The Commission's conclusion on this recommendation is discussed below under the heading "Equitable Sharing."

6. Reversal of the Company's inclusion of the unamortized balance of coal ash expenditures in rate base, to produce a 49% ratepayers / 51% investors

sharing. The Commission's conclusion on this recommendation is discussed below under the heading "Equitable Sharing."

7. Removal of the ongoing annual expense amount, or "run rate". 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 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 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 or other adjustment is proper under Chapter 62, will permit earning a full return on the unamortized balance.

Commission Determination on the Equitable Sharing Proposal

DEC proposed full recovery of its deferred coal ash costs, with the exception of fines, penalties, and costs for which it had agreed to forgo recovery. (See T 6 pp 173-74, 259) The Public Staff proposed a 49%-51% sharing between ratepayers and investors. (T 22 pp 70-85, 153-54, 162) The AGO argued that DEC had mismanaged its coal ash and that costs should be disallowed as imprudent, but did not state which costs or a specific dollar amount for disallowance. (T 11 pp 240-01) CUCA proposed a 75% disallowance of coal ash cost, based on witness O'Donnell's analysis estimating the incremental amount of coal ash costs due to CAMA above the amount that would be due solely for CCR Rule compliance. (T 18 pp 56-68) As discussed below, the Commission finds and concludes that the Public Staff's equitable sharing proposal is reasonable and appropriate in the circumstances of this case, and is within the Commission's legal authority to order.

The equitable sharing proposal is advocated by Public Staff witnesses Junis and Maness. It is opposed primarily by DEC witnesses Wright and Wells. Witness Junis testified that extensive environmental violations were caused by DEC's coal ash management, that remedial or "corrective action" to address those violations was part of the CAMA and CCR Rule costs for which DEC seeks recovery, and that DEC's responsibility for non-compliance with environmental regulations justifies an equitable sharing of those costs even without a showing of traditional imprudence. (T 26 pp 646-50, 727, 738-42) Witness Maness incorporated that recommendation from witness Junis, and added that a second reason for equitable sharing is the magnitude and unique nature of the costs, which result in no new generation of electricity for customers. He noted precedent for equitable sharing in prior Commission decisions involving losses on abandoned nuclear plant construction and environmental cleanup of Manufactured Gas Plant (MGP) facilities. (T 22 pp 70-85)

The deferred coal ash cost recovery difference between the updated positions of the Public Staff and DEC is shown in Maness Late-Filed Exhibit. For presently deferred coal ash costs, the annual amortization expense proposed by the Public Staff for coal ash costs is approximately $18.9 million for 25 years. In contrast, the annual amortization expense proposed by DEC for presently deferred coal ash costs is approximately $113.4 million for five years. These amounts do not include costs for future coal ash expenditures, which are discussed later. When combined with the removal of the unamortized balance of deferred coal ash costs from rate base, the reduction in the Company-proposed revenue requirement related to deferred coal ash costs is approximately $120.4 million.

Evidence on the regulatory treatment of coal ash costs falls into two general categories: reasonableness of costs and equitable sharing. Unreasonable costs, which may include costs resulting from imprudence, are properly disallowed under G.S. 62-133(b). Other costs may be unreasonable for regulatory purposes even though prudent for business purposes. Examples include lobbying costs, image advertising costs, and a portion of compensation for the highest Company executives. Equitable sharing, on the other hand, is the concept that even where costs are reasonable, the factual circumstances may justify sharing of certain costs between ratepayers and shareholders to achieve reasonable and just rates under G.S. 62-133(d).

The following discussion will address (1) the disallowance recommendations of witness Junis with regard to certain costs he identified as unreasonable, and (2) the equitable sharing of remaining coal ash costs as recommended by witnesses Junis and Maness. The disallowances proposed by witnesses Garrett and Moore and by other intervenor witnesses are addressed elsewhere in this Order.

Commission Determination on Legal Fees for Environmental Litigation

Witness Junis recommended disallowance of $2,109,406 (system-wide) in test year litigation costs, along with exclusion of $1,495,079 (system-wide) for extraction and treatment of groundwater that is discussed later in the Evidence and Conclusions section. The recommended disallowance for test year litigation costs are for the following cases: the state enforcement litigation involving the Allen, Belews Creek, Buck, Cliffside, Dan River, Marshall, and Riverbend plants (Mecklenburg Sup. Ct., 13-CVS-9352 and 13-CVS-14661), and the Dan River penalty assessment (OAH, 16-EHR-02477). The extraction and treatment of groundwater costs are costs associated with the Sutton penalty assessment settlement, which applied to all DEP and DEC sites in North Carolina and expressly included accelerated remediation and the installation of extraction and treatment wells at DEC's Belews Creek plant to remedy groundwater due to "offsite impacts." (See Junis Exhibit 29.)

The litigation expenses identified by witness Junis are not reasonable to charge to ratepayers where DEC has committed actual violations and the litigation expenses are for DEC's defense of enforcement action or penalty assessments. The Company points out that settlement of litigation normally precludes a judgment of liability. This does not end the Commission's inquiry; otherwise, the Company could unreasonably pass the cost of its non-feasance or misfeasance on to ratepayers simply by settling enforcement actions. The Commission must determine if the Company had a reasonable basis for incurring costs to assert a defense, which involves the question of whether allegations of environmental violations had underlying merit. Witness Wright argued that allegations of environmental violations must be admitted by the Company or found in a judicial ruling before the associated litigation costs can be disallowed from rates. (T 12 errata pp 156-33-34) This position would unduly constrain the Commission from doing its job of assessing the reasonableness of costs.

The Commission agrees with DEC that the mere fact that the Company has been sued or subject to enforcement actions for coal ash contamination is not sufficient evidence of liability or wrongdoing on the Company's part. Legal actions against DEC may or may not be meritorious. Settlements of such litigation, by themselves, do not connote liability or wrongdoing on the Company's part, nor do they indicate innocence or lack of liability. In certain situations, settlements can be a reasonable method of "buying peace" regardless of the merits of litigation.

Nonetheless, in the circumstances of the present case, the Commission finds that substantial evidence supports disallowance of the $2,109,406 adjustment for litigation costs and also the $1,495,079 adjustment for extraction well costs at Belews Creek. In support of the disallowance of legal costs for the state enforcement litigation involving the Allen, Belews Creek, Buck, Cliffside, Dan River, Marshall, and Riverbend plants (Mecklenburg Sup. Ct., 13-CVS-9352 and 13-CVS-14661), and the Dan River penalty assessment (OAH, 16-EHR-02477), Junis Exhibit 33 is a compilation of all the exhibits that show compelling evidence of environmental violations at each site, including groundwater violations and unpermitted seeps documented by DEC's own data, reporting, and stipulations on a site by site basis. The groundwater exceedances in Junis Exhibit 33 are caused by DEC's coal ash; those exceedances have been screened to remove exceedances due to naturally occurring background levels of regulated constituents. Therefore, they represent DEC's actual violations of State 2L standards.

With regard to the accelerated remediation and the extraction wells at Belews Creek agreed to in the Sutton penalty assessment and recommended for disallowance, while the Company denied wrongdoing in the Sutton settlement agreement, and the settlement explicitly states there is no admission of wrongdoing, the Company's groundwater monitoring reports show exceedances of 2L groundwater quality standards at or beyond the compliance boundaries. (Junis Exhibit 20) The Environmental Audit reports of third party experts hired by DEC show groundwater exceedances at Belews Creek, due to the ash basins. (Junis Exhibit 21) Wording in the settlement agreement between DEC and DEQ identifies offsite groundwater impacts at Belews Creek <u>due to the ash basins</u>. (Junis Exhibit 29)

In weighing all the evidence in the record on whether the litigation costs were a reasonable expense, the Commission finds overwhelming support in the compelling evidence of environmental violations for the DEQ and SELC claims against DEC with regard to the state enforcement litigation, the Dan River penalty assessment, and the Sutton penalty assessment. Details of this evidence are discussed below. First, however, there is a legal question as to whether compelling evidence of environmental violations justifies a disallowance of litigation costs and of remediation costs that are above what CAMA and the CCR Rule would have required in the absence of violations.

The Commission concludes that disallowance of such costs is legally proper. Mr. Junis cites the Glendale Water case, State ex rel. Utils. Comm'n. v. Public Staff, 317 N.C. 26 (1986), where legal expenses incurred by a utility in defense of a penalty proceeding were excluded from rate recovery as a matter of law. (T 26, pp 728-29) He quoted from the Glendale Water case as follows:

> Glendale [Glendale Water, Inc., a regulated utility] was penalized for violating serious administrative regulations, including its failure to notify its customers of contaminants in the water. It would be improper to require the very class of people the DHS sought to protect in assessing the penalty against Glendale to indirectly pay for the penalty through the inclusion of related legal fees into Glendale's operating expenses. Furthermore, since these legal fees could have been avoided had Glendale initially carried out its responsibility of providing adequate water service to its subdivisions, this expense cannot properly be considered reasonable or necessary.

In the Glendale Water case, the utility had failed to maintain chlorination equipment, leading to water contamination and boil notices for customers. The

Commission in effect penalized the utility for poor service by reducing its annual return in the amount of $1,325. However, the Commission allowed $1,938 in legal fees incurred by the utility to defend a penalty assessment brought by the Division of Health Services (DHS) in the Department of Human Resources. (<u>See</u> April 12, 1985, "Order Granting Partial Rate Increase, Requiring Service Improvements, Granting Franchise, and Approving Stock Transfer" in Docket No. W-691, Subs 25, 26, and 27; <u>Seventy-Fifth Report of the North Carolina Utilities Commission Orders and Decisions</u>, p 730) The Court affirmed the reduction on the utility's return, but reversed the allowance of legal fees related to the penalty assessment.

The <u>Glendale Water</u> case involved a wide range of service quality problems, which is not the situation in the present case with DEC. However, the wide range of service problems at Glendale Water was addressed by the Commission's return penalty. The relevance of <u>Glendale Water</u> to the present DEC case rests on two reasons stated in the Court's opinion.

First, "It would be improper to require the very class of people the DHS sought to protect in assessing the penalty against Glendale to indirectly pay for the penalty through the inclusion of related legal fees into Glendale's operating expenses." Likewise, the penalty assessment against DEC was intended to protect groundwater quality for people living and enjoying recreation in areas near the DEC generating plants. While electric service itself is not the problem, and many other DEC customers far from the groundwater impacts at each site would also have to share in the payment of legal fees, it nonetheless would be improper to require customers across the State to pay for legal fees related to DEC violations of water quality standards that are intended to protect customers and other citizens.

The water contamination in the Glendale Water case was an unusually severe threat; the groundwater contamination from DEC ash basins is an unusually widespread threat. The Commission finds that each is egregious in its own way.

Second, the Court ruled that "since these legal fees could have been avoided had Glendale initially carried out its responsibility of providing adequate water service to its subdivisions, this expense cannot properly be considered reasonable or necessary." Likewise, if DEC had complied with the State's 2L regulations and the federal Clean Water Act, its legal fees (and extraction well costs for the Belews Creek plant in the Sutton litigation) could have been avoided. Under the Glendale Water case, a litigation expense should not be allowed in rates where it is incurred to defend violations of environmental requirements. Implicit in this conclusion is the need to find there were violations. On the other hand, costs to defend cases where the Company is found not liable, or cases where there is a settlement or other resolution without clear evidence of violation, should be recoverable in rates.

In the Glendale Water case, the DHS penalty litigation had not concluded at the time of the rate case hearing. The Court noted that Glendale Water was not challenging liability, but just the amount of the penalty. DEC did challenge its liability in the Sutton penalty assessment case; however, this challenge cannot be a basis to allow its litigation costs in light of the overwhelming evidence that the Company indeed was liable for water quality violations.

The evidence of violations at the Belews Creek plant is found in multiple sources, including sources validated by DEC. One important source is the Company's reports to DEQ of the results of samples from its groundwater monitoring wells at Belews Creek. As shown on Junis Exhibit 20, DEC has violated the regulatory limits for constituents listed in 2L and IMAC standards and federal maximum contaminant levels (MCL) at the Belews Creek plant 1,926 times.[39] In his direct testimony, witness Junis made clear that he was only counting violations, not exceedances that might be due to background levels of the constituents:

> Exceedances are individual laboratory analysis results for specific parameters in groundwater that are above the acceptable regulatory concentration levels. For example, 10 sample events reporting concentration levels above the 2L standards or IMACs would result in 10 exceedances. Those exceedances may be from the same monitoring wells over months, or even years, or from multiple monitoring wells. Exceedances may be naturally occurring, or may be due to coal ash.
>
> As of the writing of this testimony, DEQ has found the most recent iteration of nearly every groundwater PBTV, including the data and the methodology to calculate the value, to be acceptable. To my knowledge, DEC has not alleged that off-site activities, outside of DEC's control, are responsible for the exceedances. Therefore, the groundwater quality exceedances in **Junis Exhibit No. 20** represent a failure to meet groundwater quality standards - a violation by DEC that is due to its coal ash - that would need to be corrected to achieve compliance with 15A NCAC 02L .0106. The violations represented in **Junis Exhibit No. 20,** with the exception of three data points that

[39] There are 3,091 groundwater violations for all seven DEC coal plants in North Carolina.

are yet to be determined by DEQ and DEC, account for the presence of any background constituents naturally present in the groundwater.

(T 26 p 701)

During cross-examination, Witness Wells was asked whether he disputed that any of the exceedances shown in Junis Exhibit 20 were not due to background levels. (T 26 p 58) Witness Wells did not dispute the accuracy of Junis Exhibit 20, acknowledged there were groundwater impacts, and responded in part that "[o]nce we have an exceedance above background outside the compliance boundary, which we have, then that activity is triggering us to do additional work, and that includes installing a lot of wells." (Id. at 58-59.)

Another objective source of violations is the 2017 Environmental Audit report for the Belews Creek plant which shows exceedances of the following constituents at or beyond the compliance boundary, as summarized in Junis Exhibit 21: boron, chloride cobalt, iron, manganese, nitrate, pH, sulfate, and total dissolved solids (with an open line of inquiry[40] on antimony, arsenic, beryllium, chromium, selenium, thallium, and vanadium). The Environmental Audits were

[40] An open line of inquiry in the Belews Creek environmental audit means that the concentrations of ash related constituents that exceeded these standards may be due to background conditions. See *Duke Energy Actions to Resolve Audit Findings,* available at https://www.duke-energy.com/_/media/pdfs/our-company/ash-management/de-actions-to-resolve-audit-findings-belews-creek-06232017.pdf?la=en.

conducted by independent consultants, reporting to Duke Energy and the Court Appointed Monitor, as a condition of the Company's federal probation.[41]

The wording in the settlement agreement (Junis Exhibit 29) between DEC and DEQ makes clear the need to remediate violations, despite the inclusion of the boilerplate statement that DEC admitted no wrongdoing. The Company's obligations under the settlement plainly reveal extraordinary action – extraction wells and water treatment – necessary to mitigate the impacts of contaminated groundwater coming from DEP and DEC ash basins and impacting property off the DEP and DEC plant sites:

> **II. DUKE ENERGY'S OBLIGATIONS**
>
> A. Consistent with 15A NCAC 2L .0106 Duke Energy shall implement accelerated remediation at the Sutton Plant on the following terms and conditions:
>
> (1) Duke Energy will commence installation of extraction wells on the eastern portion of the Sutton Plant property where data show constituents associated with the ash basins at concentrations over the 2L standards ("Constituents of Interest") have migrated off site.
>
> (2) Extraction wells will be used to pump the groundwater <u>to arrest the off-site extent of the migration</u>. The pumped groundwater will be treated as needed to meet standards and returned either to the ash basin or the discharge canal.
>
> (3) This extraction and treatment system will be installed as soon as practicable following receipt of all permits and approvals from DEQ, the issuance of which will occur as soon as practicable. <u>This accelerated groundwater remediation is in addition to and shall be performed concurrent with the coal ash impoundment closure obligations set forth in CAMA</u>.

[41] The groundwater findings in each of the environmental audit reports are summarized in Junis Exhibit 21 and can be found online in links at the webpage https://www.duke-energy.com/our-company/environment/compliance-and-reporting/environmental-compliance-plans.

(4) <u>The extraction wells shall remain operational until such time</u> as Duke Energy demonstrates through sampling, analysis, and appropriate modeling, and subject to DEQ's written concurrence, <u>that off-property constituents of interest have been remediated to 2L Standards and there is no reasonable potential for future off-site migration</u>.

(5) As part of accelerated remediation, DEQ agrees that dry ash can be <u>removed</u> from the head of the ash basins under a construction storm water permit and shall expedite such construction storm water permit in order for Duke Energy to commence the removal of ash which is the source of the constituents of interest from the Sutton Plant. DEQ will issue construction storm water permits for Sutton plant within 10 days of receiving Duke Energy's complete application. Only dry ash from the head of the ash basins will be removed with no impact to wastewater treatment or water levels in the basins. DEQ shall use its best efforts to complete the process of the issuance of the NPDES permit modification at the Sutton Plant to allow for the removal of water and ash beyond the areas covered under the construction storm water permit from the Sutton Plant.

B. Consistent with 15A NCAC 2L .0106 <u>Duke Energy shall</u> implement_accelerated remediation at the Asheville Plant, <u>Belews Creek Plant,</u> and H.F. Lee Plant, which are the only three other Duke Energy facilities that <u>demonstrated offsite groundwater impacts</u> in isolated areas that are not impacting private wells in the Comprehensive Site Assessments conducted pursuant to CAMA. Such accelerated remediation shall be tailored to each facility's unique characteristics.

(Emphasis added.) The purpose of the Belews Creek extraction wells is to arrest the offsite spread of coal ash constituents, in exceedance of 2L standards, coming from the Belews Creek plant. DEC signed on to these terms; there can be no doubt the Company had committed groundwater violations at its Belews Creek plant. During the cross-examination of DEC witness Kerin, he admitted that the extraction wells would not be needed but for the offsite groundwater impacts:

Q But with regard to Mr. Junis' statements, isn't Mr. Junis actually saying that the cost of groundwater treatment wells at Belews Creek would not have been incurred, absent environmental violations?

A The wells that were installed at Belews Creek were part of the Sutton settlement, and that was to accelerate the installation of extraction wells at Belews Creek. As we prepare our closure plan for the Belews Creek site, part of the requirements under CAMA is that we provide all the details on groundwater, all the analysis, and a Corrective Action Plan should we have exceedances that need to be addressed in the closure plan.

. . . .

Q Would a Corrective Action Plan be needed if there were not offsite groundwater impacts?

A I don't believe so.

Q Okay. And at what other locations [are] groundwater extraction wells required at DEC facilities where there are not offsite groundwater impacts?

A Currently, under the Sutton settlement, only Belews Creek was required to accelerate the installation -- as part of the settlement to accelerate the installation of extraction wells in the DEC system.

(T 24 p 171-74)

Against this evidence, the Commission gives little weight to the argument of witness Wright that legal fees should only be disallowed if there is an admission of guilt or an adjudication of guilt. (T 12 errata, pp 156-33-34) With regard to the question of whether there were violations in fact at all plants, he deferred to DEC witness Wells; yet at the same time witness Wright opposed exclusion of the legal fees. In fact, witness Wright admitted that he did zero review of the environmental violations. If witness Wright was unsure whether there were in fact violations, he had no basis for supporting or opposing exclusion of legal fees related to violations. Witness Wells argued that the exceedances identified in Junis Exhibit 20 were not the result of mismanagement (T 25 pp 58-59), but he never testified that there were no violations at DEC plant sites and no court has found that DEC did not have violations.

In addition, in the state enforcement litigation, DEQ alleged unlawful discharges from coal ash basins to surface waters of the State in violation of G.S. 143-215.1(a)(1) and (a)(6), non-compliance with NPDES permits, and known and potential groundwater exceedances in violation of the 2L rules at all DEC sites. (T 26 pp 704-05) In the Dan River penalty assessment, DEQ assessed a penalty based on the same allegations that Duke Energy pled guilty to in the federal criminal complaint, including NPDES permit violations and violations of other 15A NCAC 02B surface water quality standards at the Dan River in connection with the February 2, 2014 coal ash spill. (T 26 pp 709-12; Junis Exhibit 27)

In sum, the Commission finds overwhelming evidence of environmental violations in connection with the enforcement actions at the Allen, Belews Creek, Buck, Cliffside, Dan River, Marshall, and Riverbend plants, and the DEQ penalty assessment regarding the Dan River plant. The Commission rejects the Company's position that legal fees may only be excluded from rate recovery when there is an admission or adjudication of guilt. Adopting the Company's position would create a "moral hazard": the Company would have an incentive to settle all cases, regardless of settlement cost, because it could be assured of cost recovery in rates even when the evidence of violations was clear. The Commission concludes that a decision on exclusion of such costs should be based on all the evidence, which for the present cases overwhelmingly demonstrates environmental violations. Disallowance of litigation costs should apply in all lawsuits alleging environmental violations to the extent that either: (a) there is a final order finding DEC liable for environmental violations; (b) there is a resolution of the lawsuit other than a finding of liability – such as settlement or dismissal due to CAMA – and there is compelling evidence of environmental violations; or (c) there is a pending legal claim of environmental violations and there is compelling evidence of the violations.

The amount of money at issue on litigation fees for cases of coal ash environmental violations is remarkably small in the scale of the total rate request, and yet the principle involved is significant. As Public Staff witness Junis recommended, the disallowance of litigation costs should extend to outside legal fees, internal labor, and third party assistance such as consultants and expert witnesses retained for the litigation, in cases where either the judgments or the underlying facts show that the Company violated environmental laws or regulations. Future developments in pending legal matters may establish more environmental violations from the past, and thus the issue of whether to allow or exclude additional litigation costs could be relevant in future rate cases, and the costs may be more substantial.

In accord with the Glendale Water case, the Commission concludes that exclusion of such costs is somewhat fact-specific: it may be reasonable to allow recovery of litigation costs where liability is reasonably disputed and the Company needs to defend itself. However, as in the present case, identifiable litigation costs for extensive or severe violations, proven by the Company's own monitoring data, are properly excluded from rates.

Reasonableness of Costs:

Expenditures for Extraction Wells and Groundwater Treatment

The Commission's findings and conclusions on the exclusion of $2,109,406 of legal fees are also pertinent to the approximately $1,495,079 million in costs for extraction wells and treatment at the Belews Creek plant. The purpose of the extraction wells is to arrest the offsite migration of constituents from DEC's and DEP's ash basins. (See Junis Exhibit 29.) As stated in the settlement that DEC signed, "This accelerated groundwater remediation is in addition to and shall be performed concurrent with the coal ash impoundment closure obligations set forth in CAMA." (Id.; emphasis added.) Public Staff witness Junis recommended disallowance of the extraction well costs "because they are costs due to environmental violations, and they exceed the amount of costs required for CAMA compliance in the absence of environmental violations." (T 26 p 734) The Commission agrees. Where DEC's environmental violations increased specific costs of managing coal ash above what CAMA otherwise would have required, it would be unreasonable to allow those costs into rates.

In his rebuttal testimony, company witness Kerin argues:

> Because 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, but DE Carolinas would have installed extraction wells at Belews Creek in order to comply with CAMA even without the Sutton agreement.

(T 24 p 117)

Witness Wright, in his rebuttal testimony, with regard to the Sutton settlement and the costs of extraction wells at Belews Creek, also argues:

> 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 was imprudent, I believe environmental costs like the Belews Creek costs noted here should be recovered from ratepayers.

(T 12 errata p 156-37)

In effect, the Company witnesses argued that disallowance is improper in the absence of a showing of imprudence. The Public Staff argued that a violation of environmental regulations properly supports a disallowance, and that the extraction and treatment costs would not have been necessary under CAMA or the CCR Rule <u>but for</u> DEC's violation of State groundwater quality standards.

The Commission concludes that it is not necessary in the present case to decide if every utility violation of a law or regulation requires exclusion of remedial costs. For instance, payment of tort damages for vehicle accidents caused by Company personnel might be treated as a normal cost of business. However, that is not the case presently before the Commission. Environmental violations resulting from coal ash are a major public policy problem, from the TVA disaster, to the Dan River storm pipe collapse, to the less dramatic, but broadly damaging, impact of groundwater contamination. The EPA responded with the CCR Rule. The North Carolina General Assembly responded with CAMA. DEQ responded with enforcement actions against all Duke Energy plants in North Carolina and environmental groups intervened. South Carolina took action resulting in DEC's agreement to excavate ash from the W.S. Lee plant. The costs to address coal ash are estimated at $4.5 billion for DEC and DEP.[42] Groundwater contamination has been reported at every DEC coal plant in the Carolinas, over a period of years. In these circumstances, the Commission finds and concludes it would be unreasonable to charge ratepayers for costs of environmental violations, over and above the costs required to comply with CAMA in the absence of environmental violations. The specific costs identified in this case are the extraction well and groundwater treatment costs of $1,495,079 that should be disallowed. It is appropriate to hold the Company responsible for those costs because the costs are the direct result of violations of laws and regulations; such costs should not be deemed a normal cost of providing electric service.

<u>Reasonableness of Cost for Selenium Removal Equipment</u>

Public Staff Witness Junis recommends the disallowance of $857,350 for extra equipment to remove selenium that is in addition to the primary wastewater treatment equipment at the Riverbend plant. In testimony, witness Junis stated that the equipment was not needed and has not operated. (T 26 p 734)

The extra equipment is a SeaHAWK bioreactor system. In his rebuttal testimony, witness Kerin says the system was not operational but was purchased in anticipation of rising selenium levels in the interstitial waters as the excavation

[42] The December 30, 2016, DEC and DEP Petition for an Accounting Order in Docket Nos. E-2, Sub 1103, and E-7, Sub 1110, states in part: “the total value of the Companies' AROs recorded as of September 30, 2016 related to coal ash basin closure costs to date is approximately $4.5 billion.” Of that amount, $2.1 billion is for DEC.

at the Riverbend site progressed and was needed to comply with selenium limits required in the Riverbend NPDES permit. (T 24 pp 117-19) During cross-examination at the hearing, DEC witness Kerin said that the equipment was put into operation in mid to late February of this year. (T 24 p 176)

With regard to witness Kerin's testimony, the Commission finds that it does not support a conclusion of "used and useful" for the SeaHAWK system because (a) there is no evidence to substantiate witness Kerin's statement that the late February use of the system was necessary to achieve compliance with selenium standards (i.e., that the other compliance methods used by DEC would have been inadequate without the supplemental use of the SeaHAWK system); and (b) there is no evidence indicating that there is an ongoing use of the SeaHAWK system, as opposed to a one-time use that will not be repeated.

In a response to a Public Staff Data Request, the Company provided selenium level data from October of 2016 through January of 2018 which showed no exceedances of selenium limits. (Public Staff Kerin Rebuttal Cross Examination Exhibit 1) Witness Kerin testified that, while there were no selenium exceedances during that time frame, as the excavation got deeper into the interstitial water, "we started to see the trend going up in the third and fourth quarter of 2017, and we installed the system in early '18." (T 24 pp 177-78)

According to the Company's environmental compliance plan submitted to DEQ, the excavation at Riverbend is over a year ahead of schedule. (<u>See</u> Public Staff Kerin Rebuttal Cross-Examination Exhibit 2, at p 15, which states that the anticipated completion date of excavation at the Riverbend site is July 13, 2018) Further, there were equalization or "EQ" basins in place at the site to allow the Company to have control over the amount of water or flow of water being discharged under the NPDES permit. (T 24 p 181)

Accordingly, and in the absence of sufficient evidence to the contrary, the Commission finds that the selenium levels could have been maintained below NPDES permit limits by the same methods the Company had been using until mid to late February of this year when the system was first activated. At a minimum, the Commission finds that there is insufficient evidence that the SeaHAWK system is being used on a going-forward basis. The Commission agrees with the Public Staff's recommendation to disallow the costs of the system.

Equitable Sharing Proposal

Public Staff witnesses Junis and Maness recommended an "equitable sharing" of coal ash costs that are not otherwise disallowed. Specifically, witness Maness proposed a 25-year amortization period, with no return on the unamortized balance, resulting in the ratepayers bearing approximately 49% of DEC's request for recovery of coal ash costs incurred between January 1, 2015, and December 31, 2017.[43]

[43] Initially the Public Staff recommended a 27-year amortization designed to achieve a 50%-50% sharing of coal ash costs between ratepayers and investors, based on the Public Staff's recommended cost of capital. Once cost of capital was settled between DEC and the Public Staff, witness Maness filed settlement testimony that adjusted his amortization period to 25 years,

In contrast, DEC proposed a five-year amortization of all its requested coal ash costs incurred between January 1, 2015, and December 31, 2017, with a return at the proposed settlement cost of capital on the unamortized balance. The difference between the updated positions of the Public Staff and DEC is shown in Maness Late-Filed Exhibit. For presently deferred coal ash costs, the annual amortization expense proposed by the Public Staff for coal ash costs is approximately $18.9 million per year for 25 years. In contrast, the annual amortization expense proposed by DEC for presently deferred coal ash costs is approximately $113.4 million per year for five years. These amounts do not include costs for future coal ash expenditures, which are discussed later. Additionally, the Company proposed to include the unamortized balance of deferred coal ash costs in rate base, which in this proceeding would increase the revenue requirement by approximately $25.6 million.

As noted in discussion above, Company witnesses in direct testimony maintained that the coal ash costs included in the present rate request were prudent and reasonable environmental compliance costs. Their testimony identified new legal obligations under the CCR Rule and CAMA, giving rise to AROs for GAAP purposes for ash basin closures and related activities. These AROs were modified for regulatory accounting and ratemaking purposes into the deferred coal ash expenditures for which the Company requests recovery in this

reflecting the intent to achieve close to the 50%-50% sharing with the stipulated cost of capital (to keep the amortization to a whole number of years, it changed slightly to 49%-51%).

rate case through amortization (with a return on the unamortized balance). The Company requested full rate recovery for the deferred coal ash costs. In rebuttal and in cross-examination, the Company challenged the equitable sharing proposal on a number of fronts, discussed below.

The Public Staff testified to two general reasons for an equitable sharing. First, as noted by witness Maness, past Commission decisions and a ruling of the North Carolina Supreme Court provide support for equitable sharing in unusual circumstances. (T 18 pp 309-13) In his opinion, the nature and magnitude of coal ash costs make them appropriate for equitable sharing. Witness Maness testified that even if the reasons for equitable sharing set forth by Mr. Junis were not present, the Public Staff still believes that some level of sharing, perhaps comparable to that previously used for abandonment losses on cancelled nuclear generation facilities, would be appropriate and reasonable for DEC's coal ash costs. (T 22 p 72)

Second, as stated by witness Junis, "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." (T 26, p 738) He testified that some environmental violations "are not easily characterized as either strictly imprudent or strictly reasonable on DEC's part." (T 26 p 723)

Where violations are due to the Company's imprudence, the costs are unreasonable and should be totally excluded from rates. Where costs are entirely reasonable, they typically (but not always) would be included entirely in rates. These regulatory outcomes are based on G.S. 62-133(b). However, the law also allows for a middle ground – an equitable sharing – when otherwise prudent costs would be unreasonable or unjust to include in rates under G.S. 62-133(d). Because the middle ground of equitable sharing alters the normal practice of allowing appropriate, prudent, and reasonable costs into rates, it should be applied only in specific circumstances where the magnitude and nature of the costs makes it necessary to reach a fair and reasonable outcome.

Witnesses Junis and Maness have described unusual and compelling circumstances in the present case. First, there is no doubt that coal ash costs are extraordinary in both nature and amount. The Company, in its April 19, 2017, Reply Comments in Docket No. E-7, Sub 1110, justified its deferral request for coal ash costs, in part, on the basis of "the extraordinary nature and uniqueness of the costs requested to be deferred (and the magnitude of the costs)." In its December 30, 2016, Petition for an Accounting Order in the same docket, the Company stated it had recorded AROs estimating coal ash compliance costs of $2.1 billion for DEC and $2.4 billion for DEP. Moreover, the nature of the costs is more analogous to cleanup costs for MPGs, for which there has been equitable sharing in some cases, than anything else before the Commission. The one relevant difference between MGP environmental cleanup costs and coal ash environmental cleanup costs is that the coal ash costs are orders of magnitude greater. The new coal ash costs represent additional disposal costs for the same ash that was first deposited in the basins, without the benefit of any additional electricity being produced. In other circumstances, the enactment of new environmental requirements may justify full recovery of costs, but with DEC coal ash disposal, a significant portion of the costs result from the Company's failure to comply with pre-existing environmental regulations. Furthermore, witness Maness pointed out that the Commission has taken an equitable sharing approach several times in past cases involving generating plants, most often in the cases of nuclear and coal plants abandoned prior to commencing commercial operation, including, specifically for DEC, the abandonment loss related to the Cherokee Plant (Units 1, 2, and 3), as addressed in Docket No. E-7, Sub 358. Mr. Maness also testified that the equitable sharing approach has been upheld by the North Carolina Supreme Court, as clearly expressed in State ex rel. Utils. Comm'n v. Thornburg, 325 N.C. 463 (1989).

DEC maintains that its deferred coal ash costs have been incurred to comply with the CCR Rule and CAMA. The Commission finds this contention is true with respect to the costs for which the Public Staff has proposed equitable sharing. CAMA requires groundwater assessments, corrective action plans to remediate contamination risks, and closure of the ash basins. However, the Commission also finds that the CCR Rule and CAMA compliance costs incurred by DEC substantially substitute for costs that otherwise would have been incurred to remediate environmental violations caused by DEC. Corrective actions and closures of ash basins required by the CCR Rule and CAMA essentially duplicate the remediation efforts that would have been required pursuant to 2L regulations, G.S. 143-215.1, and other legal requirements. The need for corrective action reflects DEC's culpability for failure to comply with long-standing environmental laws and regulations.

As a matter of law, the duty to comply with G.S. 143-215.1, NPDES permit conditions, and the 2L groundwater regulations exists without regard to whether the Company was prudent or imprudent. DEC had a legal responsibility to prevent – not merely to respond to – groundwater and surface water contamination. To the extent DEC's failure to meet its legal responsibility resulted in remediation costs, and either it is unclear whether the costs were the result of imprudence, or the cost is subsumed under general CAMA compliance costs and cannot be separately quantified, it is reasonable and appropriate for those costs to be equitably apportioned between ratepayers and shareholders.

The extent of environmental violations committed by DEC is revealed in Public Staff exhibits. There are deficiencies in dam safety that required repairs (Junis Exhibits 11 and 12), penalties in special orders by consent in connection with unauthorized discharges to surface waters (Junis Exhibits 18 and 19), and further unpermitted discharges to surface waters in violation of G.S. 143-215.1 (e.g., seeps admitted in the Joint Factual Statement from the federal criminal plea in Junis Exhibits 31 and 32 and identified in the Environmental Audit reports in Junis Exhibit 22). However, most significant among environmental violations are the groundwater violations at every DEC coal-fired plant in the Carolinas (the number of violations from DEC's own reporting data summarized in Junis Exhibit 20, maps of the groundwater plumes shown in Junis Exhibit 26, and the

Environmental Audit reports summarized in Junis Exhibit 21). The groundwater violations are extensive: 3,091 violations of groundwater quality standards across the North Carolina plants, due to migration of constituents from ash basins and not due to natural background levels (Junis Exhibit 20).

In addition, the Company admitted to 13 unpermitted engineered seeps (Public Staff Wright Cross-Examination Exhibit 2, response to Public Staff data request 55-32). While the total number of seeps exceeded 200 across the DEC and DEP plants in the State (<u>see</u> Junis Exhibit 31), the engineered seeps are especially problematic. These are <u>intentional</u> acts by the Company, in complete disregard of the statutory permitting requirement in G.S. 143-215.1 and the federal Clean Water Act that are intended to protect North Carolina waters from pollution.

DEC's position that its coal ash costs were necessary to comply with the CCR Rule and CAMA misses an essential point. The Company's extensive environmental violations, occurring at all its plants across the Carolinas, would have required remediation at considerable expense even without the CCR Rule and CAMA. It would be inequitable and poor public policy to conclude that enactment of the CCR Rule and CAMA should shield DEC from cost responsibility for its violations. Certainly, there is no indication that the EPA or the General Assembly intended to shield the Company from this cost responsibility. Cost responsibility is appropriately a question left to the Commission, and the Commission concludes that the costs of remedying contamination flowing from DEC's ash basins should not be entirely the responsibility of ratepayers.

As Public Staff witness Junis testified (see, e.g., T 26 p 727), most of the costs of remedying environmental violations cannot be quantified independently of CAMA and CCR Rule compliance costs. The reason is that those remedial costs require speculation as to alternative scenarios that did not occur. Specifically:

(1) While certain sites have had the non-constructed or non-engineered seeps addressed by SOCs to decant and dewater the basins on an accelerated schedule, at several sites DEQ is still determining which of the existing unauthorized constructed or engineered seeps will be allowed under new NPDES permits;[44] (T 26 pp 697-98)

(2) A number of lawsuits involving existing contamination from ash basins and the appropriate closure methods at the Allen, Belews Creek, Cliffside, and Marshall plants, are in active litigation, so the costs of remediation and closure are yet to be determined; (T 26 p 706)

(3) Arguably, the costs of remediating groundwater contamination from ash basins should be netted against the costs of installing liners at the time the basins were constructed, but the costs of installing liners decades ago is too speculative to accurately quantify; and alternatively, the costs to retrofit existing basins or convert to dry ash disposal decades ago are also too speculative to accurately quantify; (T 26 p 725) and

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[44] SOCs have been approved for Riverbend, Allen, Marshall, and Cliffside/Rogers. (See the following footnote for more details on updates to Allen, Marshall, and Cliffside SOC since the conclusion of the hearing) The SOCs for Buck and Belews Creek are still pending. The revised NPDES permits for all sites except Riverbend, which are expected to incorporate the constructed or engineered seeps, have not been approved to date.

(4) The costs of remedying violations in response to citizen action and DEQ enforcement lawsuits if there had been no CCR Rule and CAMA is also too speculative. For example, CAMA ultimately required closure by excavation of coal ash at two of the seven DEC coal-fired plants in North Carolina. Whether judgments in the enforcement lawsuits would have also required closure by excavation, as opposed to less expensive methods such as cap in place, is too speculative to know. (T 26 pp 725-26)

What is known is that the extensive coal ash-related environmental violations documented in data reported to DEQ require costly corrective action. Whether the corrective action is required under 2L regulations and Chapter 143, or under the CCR Rule and CAMA, it reflects DEC's failure to comply with environmental standards and thus justifies DEC sharing an equitable part of the costs.

Given the practical impossibility of identifying precisely what the costs of coal ash remediation would have been in the absence of the CCR Rule and CAMA, and given DEC's culpability for violations, an equitable sharing of actually incurred coal ash costs is appropriate. Given the high number of environmental violations resulting from DEC's failure to comply with long-standing regulations and laws, it is just and reasonable to require shareholders to bear a greater portion of the costs than in nuclear plant cancellation costs, where Company culpability was not so evident.

The Company's challenge to the Public Staff was framed in terms of prudence analysis, which is different from the Public Staff's equitable sharing position. Imprudent acts or omissions would give rise to a 100% disallowance of costs under G.S. 62-133(b). The equitable sharing of coal ash costs is instead based on DEC's failure to comply with environmental laws and regulations, which shows Company culpability without regard to imprudence. It is also based on the uniqueness and magnitude of the costs, which are factors underlying previous equitable sharing decisions of the Commission. For equitable sharing, as opposed to prudence, the applicable statute is G.S. 62-133(d).

Where DEC witnesses did challenge the Public Staff's actual position, they did not provide persuasive evidence. For witness Junis, the central reason for equitable sharing was the extensive environmental violations, which required costly remediation. Witnesses Wright and Wells (and Kerin and Fountain) argued that the Company had an "outstanding" environmental compliance record with respect to coal ash. Witness Wells specifically stated, "the Company's NPDES permit compliance has been outstanding." (T 24 p 226) The Commission disagrees.

The goal of the NPDES permitting program or National Pollutant Discharge Elimination System, is to reduce and eliminate the discharge of pollutants to the surface waters, as its name suggests. The Company takes the position that because it mostly complied with the numerical water quality standards established in the permits <u>at the permitted outfall</u>, except for the Dan River spill and the engineered seep at Riverbend for which it was criminally negligent (Junis Exhibit 32), it has had outstanding NPDES permit compliance. However, where the company has seeps that flow to the waters of the State or the waters of the United States, those flows are not being monitored at the outfall and, thus, are required to be included in the permit. The Company is not or was not in compliance with the Clean Water Act, which establishes the NPDES permitting system, or G.S. 143-215.1, where coal ash constituents from seeps reach a water of the State or the United States and are not properly permitted.

The issues raised by witness Wells in his rebuttal testimony were addressed in witness Junis' environmental compliance exhibits. In Junis Exhibits 18 and 19, DEC agrees to pay a penalty for 33 seeps in special orders by consent; 12 at Riverbend and 21 at Allen, Marshall, and Cliffside. The Riverbend SOC, contains a $48,000 penalty and states that "Duke Energy is responsible for unauthorized discharges of wastewater from around the Riverbend Steam Station's coal ash impoundments . . . ." (Junis Exhibit 18) Similarly, the draft SOC for Allen, Marshall, and Cliffside/Rogers contains a penalty for $84,000 (Junis Exhibit 19) but has subsequently been revised and approved by the Environmental Management Commission (EMC) with an increased penalty of $156,000.[45]

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[45] The revised SOC was approved at a special meeting of the EMC held on April 12, 2018, *available at* https://files.nc.gov/ncdeq/Environmental%20Management%20Commission/EMC-2018/April_2018/SOC_%20S17-009_Revised06Apr2018.pdf.

In direct testimony, witness Wells states that "SOCs are a regulatory mechanism that provide regulatory clarity and alignment with respect to the scope and schedule for compliance related activities given a change in circumstances, such as a change in requirements or change in operations." (T 24 p 253) However, the plain language of the statute authorizing the EMC to enter into SOCs, G.S. 143-215.2, states that the EMC may issue the order "to any person whom it finds responsible for causing or contributing to any pollution of the waters of the State . . . ." (Public Staff Wells Cross-Examination Exhibit 1) Furthermore, DEQ's policy on SOCs states that "SOCs may be an appropriate course of action if a facility is unable to consistently comply with terms, conditions, or limitations in an NPDES permit." (Public Staff Wells Cross Examination Exhibit 2) Witness Wells' description of the purpose of entering SOCs as "a regulatory mechanism to provide regulatory clarity" (T 24 p 253) is an attempt to minimize the actual purpose of the SOCs as a regulatory enforcement tool designed to bring a permittee who is out of compliance with its NPDES permit back into compliance. However, this ignores the fact that the SOCs are based on Notices of Violations and include express monetary penalties against DEC. (Junis Exhibits 19 and 20)

Junis Exhibit 20 shows there are over three thousand violations gathered from DEC's own reporting data, which are above background levels agreed to with DEQ. When asked about Junis Exhibit 20 on cross-examination, witness Wells admitted that there are groundwater impacts at all DEC sites and did not dispute the validity of the data presented in Junis Exhibit 20. (T 26 pp 57-59)

In other rebuttal testimony, the DEC witnesses inaccurately paraphrased Public Staff testimony, creating a straw man that they then criticized. Witnesses Wells and Wright distorted witness Junis' statement that the Dan River spill was a "contributing factor" to the enactment of CAMA and the CCR Rule by claiming that witness Junis incorrectly said that Dan River was the "proximate cause" of the CCR Rule. There is ample support for witness Junis' "contributing factor" testimony. CAMA was enacted in response to the Dan River spill, though it addressed a broader range of environmental issues associated with coal ash. Junis Exhibits 34, 35, and 36 show the Dan River spill was a major impetus for the CAMA legislation. Witness Wright's opinion that legislation equivalent to CAMA would have been passed in North Carolina in the absence of the Dan River spill is unfounded speculation. Likewise, the Federal Register publication of the final CCR Rule shows that the Dan River spill was mentioned multiple times by the EPA in support of adoption of the Rule. Witness Wright is correct that the proposed CCR Rule was published before the Dan River spill, but this does not mean the Dan River spill did not lend further support (was a "contributing factor") to adoption of the final CCR Rule.

Witness Wright contended that witness Junis had stated that environmental lawsuits and settlement payouts were "per se" evidence of imprudence or liability. (See T 12 errata p 156-32) Witness Junis did testify that the "Public Staff does not assert that the sheer number of legal actions against DEC for coal ash environmental violations is evidence of the Company's guilt, but it does suggest the extent of the problem." (T 26 pp 739-40) However, witness Junis does not make a “per se” argument. The central focus of witness Junis’ position is that the Company’s own reporting data and responses to data requests show extensive environmental violations that are compelling evidence of the company’s record of noncompliance. That evidence is in Junis Exhibits 18, 19, and 20 as well as his testimony and summarized by case and docket number in Junis Exhibit 33.

In direct testimony, witness Junis did testify that litigation costs should be disallowed to the extent that either: (a) there is a final order finding DEC liable for environmental violations; (b) there is a resolution to the lawsuit other than a finding of liability – such as settlement or dismissal due to CAMA – and there is compelling evidence of environmental violations; or (c) there is a pending legal claim of environmental violations and there is compelling evidence of the violations. (T 26 p 729) In Junis Exhibit 33, the compelling evidence of environmental violations is summarized for each litigation that included test year costs for which he has recommended the disallowance of test year litigation costs. The Commission has determined that the groundwater monitoring data and other evidence, independent of settlement payments, establish that there were groundwater violations, unpermitted seeps, and violations of other surface water quality standards across the DEC system; therefore, the test year litigation expenses identified for the Dan River penalty assessment and the state enforcement litigation should be disallowed.

In rebuttal, witness Wright further challenged the Public Staff recommendation as being inconsistent with the Public Staff’s position in the 2016

DNCP rate case. He pointed out that Dominion had been sued by the Sierra Club for coal ash-related environmental violations, so that Dominion was "similarly situated" to DEC, and that the Public Staff recommended full recovery of coal ash costs in the DNCP rate case rather than an equitable sharing. (T 12 errata pp 156-12-14) He also argued that DEC's coal ash disposal costs are "used and useful" and therefore a return is appropriate on the deferred amount. (T 12 errata p 156-16) With regard to the Sierra Club lawsuit against Dominion, witness Wright admitted the decision came after the 2016 DNCP rate case. (T 21 p 190) He admitted that in the DNCP case, there was no challenge to the reasonableness of coal ash cost recovery, whereas in the present case there were challenges. (T 13 p 68)

The documented environmental problems of Dominion have been very small, to date, in comparison to those of DEC. During the Dominion rate case that witness Wright references, Docket No. E-22, Sub 532,the Public Staff pursued information on Dominion's environmental violations in a data request asking if there have been findings of violations, assessments, fines, or penalties by the Virginia DEQ. (Public Staff Wright Cross-Examination Exhibit 3) Dominion responded that it had received a warning letter from the Virginia DEQ in 2015 regarding a minor spill. (Junis Exhibit 37) This level of environmental regulatory action against Dominion pales in comparison to the regulatory record of DEC on coal ash groundwater exceedances, unpermitted seeps and other discharges, payments arising from a state penalty assessment, and ongoing litigation where DEC's own monitoring records show violations. Witness Maness also pointed out that in the Dominion case, the total paid-to-date system costs in question were only approximately 12% of the total paid-to-date system costs at issue in this case, and that the Commission's decision regarding the amortization period in that case was explicitly noted as not being binding upon the Commission in future Dominion cases.

The Commission finds that there was no significant evidence of environmental violations in the 2016 DNCP rate case, in contrast to the present case. Another important distinguishing factor is that the magnitude of DEC coal ash costs is vastly larger than the DNCP coal ash costs in Docket No. E-22, Sub 532. Additionally, as a settled case with tradeoffs on various issues, the 2016 DNCP rate case cannot be considered as any type of precedent for regulatory treatment of coal ash.

Moreover, the Commission concludes that witness Wright is incorrect in stating that DEC's coal ash costs are "used and useful" utility property within the meaning of G.S. 62-133(b). Public Staff witness Maness testified that in North Carolina utility regulation, the term "used and useful" only applies to the public utility's property, not the expenses it incurs in the operation, maintenance, or disposal of that property. (T 22 pp 77-78) 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. (Id. at 78) Instead, they are allowed to be recovered from the ratepayers on an ongoing basis as operating expenses, if they themselves are determined by the Commission to be reasonable and prudently incurred. (Id.) If, however, there are expenses that were incurred in the past, but for some reason the Commission decides that they can be deferred for recovery in the future, the Commission can approve a regulatory asset to capture such expenses, and even provide for a return on them. (Id.) This treatment is within the discretion of the Commission, but it does not transform the Commission-created regulatory asset into capitalized property cost, such as the cost of a generating plant. The two types of costs are fundamentally different from one another. (Id.)

Witness Maness further testified that the costs should fall into the category of a deferred expense for the following reasons. First, the Company has itself chosen to request 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. (T 22 p 79) Instead, the Company has proposed to utilize an accounting and ratemaking model that accounts for and recovers the coal ash cleanup costs as expenses on an “as-spent” or “as-accrued” basis, without specific identification of or accounting for any costs as plant in service or other property. (Id.) Second, the costs proposed for deferral and amortization themselves are not in any manner costs related to present or future operations; instead they are costs that, but for Commission approval of the deferral and amortization, will be immediately written off as expenses related to the past. (Id. at 80-81)

Company witness Doss presented rebuttal to challenge the position of Public Staff witness Maness that the Company had chosen to depart from Asset Retirement Obligation (ARO) accounting as mandated by the Financial Accounting Standards Board (FASB). During cross-examination, Public Staff witness Maness explained the difference between ARO accounting as required (absent regulatory action) under Generally Accepted Accounting Principles (GAAP) by the FASB versus the regulatory accounting being requested and used by the Company. He stated that in approximately 2003, the Company filed a petition or motion with the Commission in Docket No. E-7, Sub 723, in which it asked to depart from ARO accounting as then newly prescribed by the FASB, and instead continue to account for nuclear decommissioning costs using the methodology that the Commission had been following for many years. The expenses for nuclear decommissioning that would have been recorded under the FASB's ARO approach appeared to be significantly different than the method then approved by the Commission. Witness Maness stated that ARO accounting is a term coined by the FASB (and subsequently adopted by the Federal Energy Regulatory Commission (FERC)) that describes a method with very prescriptive requirements for determining how much an ARO will be and how much the expense will be in order to spread that ARO over several years. The Commission approved the Company's motion to record regulatory assets and liabilities in order to match up their recognition of nuclear decommissioning expense with the method that the Commission had long adopted for determining the revenues to be recovered each year to cover that expense.

Witness Maness testified that until this proceeding, nuclear decommissioning has been the major item for which a Company has asked to depart from ARO accounting as prescribed by the FASB. However, in this case, the Company first filed a letter near the end of 2015 in which it indicated that for coal ash cleanup, it was following the example set by the Commission’s Sub 723 Order, which would be a departure for this Commission's regulatory purposes from ARO accounting to a methodology which would instead look at expenses as they were incurred (or as underlying equipment might be depreciated) and follow an as-spent or as-accrued basis for recognizing costs. Then, at the end of 2016, the Company actually filed a petition with the Commission in which it asked that the actual as-spent or as-expensed costs that they incurred be accrued in a deferred asset and allowed to be recovered from the ratepayers. Thus, for purposes of accounting and ratemaking before this Commission for North Carolina retail regulatory amounts, the Company has asked to depart from the method that has been approved by the FASB and FERC, and recover its costs on a different basis, also recognizing expenses in its regulatory books of account for this Commission on that basis rather than the method prescribed by the FASB and FERC.

Witness Maness stated that Company witness Doss was viewing this issue from the viewpoint of the financial statements that the Company prepares for its investors. Mr. Maness indicated that witness Doss is correct that the Company has to pay attention to the requirements and actions of several entities that have some control over how it accounts for its costs, including the Securities and Exchange Commission, the FASB, the FERC, and this Commission, as well as the South Carolina Public Services Commission. However, he stated that what he thought witness Doss' testimony failed to identify is the fact that for this Commission's purposes, the Commission's regulatory accounting action actually displaces and replaces the FASB and FERC methodology. As he stated, "Mr. Doss is right when he says, well, we have to pay attention to A, B and C. But then he really does not eliminate [sic: consider] the fact that C has the effect of cancelling out A and B, at least for the accounting and ratemaking authority of this Commission as applied to ratemaking for Duke Energy Carolinas' North Carolina retail operations." (T 22 pp 176-81)

Later during cross-examination, when he was asked if he was saying that GAAP rules mattered, he stated,

> No, I didn't say it doesn't matter to me what the GAAP rules apply. I fully support that for purposes of presenting its financial statements to investors,that the Company comply with generally accepted accounting principles.
>
> However, you — for this Commission's ratemaking decisions, that has to be balanced against what is right for the ratepayers and what is fair and reasonable in rates. And I do not believe that the Commission should put GAAP requirements over its own determination of what is fair and reasonable, no matter what the outcome might be in terms of the GAAP financial statements.
>
> (T 22 p 206)

Additionally, witness Maness testified that witness Wright's assertion that the unamortized coal ash cleanup costs qualify as working capital is incorrect because in his opinion, this classification is just a matter of convenience. (T 22 pp 81-82) True working capital is the investment made in materials and supplies, cash, and other similar items to finance and provide for the Company's present and future operations; in other words, to "do the work" of providing ongoing utility service. (Id.) The proposed deferred coal ash compliance costs are expenses incurred in the past that the Company proposes to recover in the future; they have nothing to do with the Company's forward-looking obligation to provide utility service. (Id.) Normally, it does no harm for the Company to group many disparate items under the heading of working capital; however, one should not mistake the inclusion of the proposed coal ash cost deferred costs in this group for actual evidence that such costs are in fact "working capital." (Id.)

The original cost of ash impoundments may well be in rate base, earning a return, as used and useful property. That is irrelevant to the ARO costs for compliance with CAMA and the CCR Rule (or remediation of environmental violations) that DEC has requested be deferred into a regulatory asset. DEC has not sought to include these costs in rate base as utility plant under G.S. 62-133(b)(1). DEC's decision – its choice – to defer these costs into a regulatory asset treats these costs a form of expense, which by statutory definition is different from used and useful property. Furthermore, the "expense" classification of coal ash remediation costs is supported by the testimony of DEC witness McManeus, who described the coal ash costs as "O&M" expense for purposes of the

Company's run rate proposal. (T 6 pp 260-61) There is no reason why past deferred coal ash costs would be any different from future coal ash costs, for regulatory purposes. Nor does the Commission accept that DEC's labeling of past deferred coal ash costs as "working capital" actually make them working capital; to do so would elevate form over substance for the reasons stated by witness Maness. Once DEC deferred its coal ash costs, those costs became properly classified as expenses, with the cost recovery of the regulatory asset being permissible through amortization. The unamortized balance of deferred expenses, unlike the undepreciated part of costs for used and useful utility property, is not legally entitled to a return. Indeed, this is the basis for the North Carolina Supreme Court affirming an equitable sharing of cancelled nuclear plant costs in State ex rel. Utils. Comm'n v. Thornburg, 325 N.C. 463 (1989).

Witness Wells argued that groundwater exceedances are a function of how modern laws have changed the way unlined basins are viewed. However, the 2L regulations were adopted in 1979, and witness Wells' own testimony shows the corrective action requirements were added to 2L by 1984. Thus, over 30 years have elapsed since DEC was required by the State's 2L regulations to prevent and correct groundwater contamination. Given that 2L has been the law for over three decades, and that many of DEC's violations have been determined in recent years, the Commission is not persuaded that the fact that there were changing environmental regulations should excuse the 3,091 violations shown in Junis Exhibit 20.

Furthermore, in direct testimony, Witness Wells stated that "the Company did not ignore the risk of groundwater contamination" and that groundwater monitoring was done by the utility at the Allen plant starting in 1978. (T 24 p 230) Based on the data obtained from those few initial monitoring wells, the Company produced two internal reports that concluded that there were no significant groundwater impacts at Allen and Riverbend in 1984 and 1987, respectively, despite exceedances of water quality standards at the time. (See Public Staff Wells Cross-Examination Exhibits 7-8) The groundwater monitoring data that the internal reports relied on was taken from a network of only 13 wells installed and monitored for only four years. (T 26 p 50) Given that concentrations of certain constituents, including boron, a constituent known to be a coal ash tracer, were over water quality standards at the time and the 2L rules had recently been adopted, the Commission disagrees with the Company's assertion that it did not ignore the risk of groundwater contamination at that time.

Likewise of concern to the Commission, witness Wells testified that DEC has taken every action required by DEQ and CAMA to address groundwater impacts. In fact, DEC litigated for years against the DEQ efforts to obtain corrective action through its state court enforcement cases brought in May and August of 2013. (See Public Staff Wright Cross-Examination Exhibit 1) Moreover, the 2L regulations require first and foremost that groundwater exceedances be prevented, whereas witness Wells touts the virtue of the Company's efforts to clean up its violations. The Commission finds that the large extent of groundwater violations is not a model of compliance as the Company witnesses claim; rather, it shows a widespread failure to comply. This in turn justifies an equitable sharing of the associated costs.

Witness Wells testified that unlined ash basins were the primary technology when DEC built its basins. (T 24 p 228) The Commission agrees. At the same time, this fact is more relevant to a prudence analysis than to the equitable sharing issue. The Commission accepts that the DEC approach to ash basin construction (i.e., no liners) was consistent with a majority of other electric utilities in the 1957 to 1980 time period. Whether DEC should have known in past decades that ash basins could contaminate groundwater in the absence of liners is less clear. Junis Exhibits 3 through 10 show that the industry was aware of the growing trend away from the use of unlined basins due to the risk of groundwater contamination.

It is apparent that there was some understanding of groundwater risk well before industry standards changed. However, the salient fact is that once 2L regulations were adopted in 1979, the Company had a legal duty to prevent groundwater contamination, and also a duty after 1983 to take corrective action where contamination did occur. Following standard industry practice did not exempt DEC from its legal duty to comply with 2L groundwater standards.

In this regard, the Commission finds it was unreasonable for DEC to delay installation of comprehensive groundwater monitoring wells for years after the 2L groundwater quality requirements became effective. DEC installed a few wells in a discrete study for three years at Allen in the early 1980s, four wells at Dan River in 1993, four wells at W.S. Lee in 1993, and other voluntary monitoring wells beginning in 2004. (DEC Late Filed Exhibit, March 21, 2018) This was a paltry number of monitoring wells; indeed, prior to the commencement of DEQ enforcement actions in 2013 the Company had only installed 383 wells across all its North Carolina plants. By contrast, in November of 2017, with comprehensive assessment required in the wake of CAMA, the Company had installed 1,407 groundwater monitoring wells. (Junis Exhibit 25) The disparity shows that DEC was not making a sufficient effort to assess its groundwater compliance until after the Dan River spill brought attention to ash basin environmental problems.

Witness Wells observed that 2L did not create a legal duty to install monitoring wells; only later – starting in 2009 – did DEQ start to systematically add groundwater monitoring to NPDES permit conditions. (T 24 p 231) However, given that the duty to comply with 2L began in 1979, and corrective action was required by 1984, it was not possible for DEC to know if it had significant violations requiring corrective action without monitoring. It appears that the Company simply relied on lack of enforcement action by DEQ, which is not a reasonable strategy either in terms of actually complying with the regulation or in terms of proactively avoiding greater cleanup costs in the future by identifying problems in earlier years before they spread far or accumulated.

Witness Wells disagreed with witness Junis' statement that comprehensive monitoring and remediation did not begin until after the state enforcement litigation (2013), the Dan River spill (2014), and CAMA (2014). However, as noted above, the number of monitoring wells prior to 2013 was 383 – hardly comprehensive compared to the 1,407 in November of 2017. The importance of having a large number of monitoring wells was noted in the Federal Register publication of the CCR Rule. Page 21455 states "once monitoring is put in place, new damage cases quickly emerge."[46] Further, the CCR Rule cited North Carolina as an example, noting that as new monitoring wells were required in 2012, DEQ "disclosed that elevated levels of metals have been found in groundwater near surface impoundments at all of the state's 14 coal-fired power plants."

Sierra Club witness Quarles also testified to the need for a large number of groundwater monitoring wells. When asked whether a few sampling wells or a large number of wells is needed to properly assess the risk of contamination, he responded:

> A large number. These [facilities] are hundreds of acres, so therefore it requires hundreds of wells, and particularly when you're talking surface impoundments because that process introduces sluice water into the impoundment, so that creates a mounding effect. So that complicates a traditional groundwater monitoring program because mounding can produce [radial] groundwater flow in all directions. So, therefore, you need to have adequate spacing of wells that are traditionally thought to be upgradient when, in fact they may be downgradient.
>
> (T 6 p 139)

Voluntary monitoring wells were put in place, starting with the Allen site in 2004, but the monitoring networks were only a fraction of the wells that would be

[46] See https://www.federalregister.gov/documents/2015/04/17/2015-00257/hazardous-and-solid-waste-management-system-disposal-of-coal-combustion-residuals-from-electric.

needed for such large facilities. In response to an inquiry on the start of groundwater monitoring at each site from Commissioner Clodfelter during the hearing, the Company filed an exhibit on March 21, 2018, with information on the voluntary monitoring wells at each site, as shown below.

Plant	**First Sample Date**	**Number and Description of Wells**
Allen[47]	November 2, 2004	6 wells at 4 locations. Locations AB-02 and AB-04 each had a shallow and a deep well.
Belews Creek	November 14, 2007	8 wells at 4 locations. All locations each had a shallow and a deep well.
Buck	November 14, 2006	12 wells at 6 locations. All locations each had a shallow and a deep well.
Cliffside	August 25, 2008	15 wells at 11 locations. 6 locations had both shallow and deep wells. (Some of these wells had been installed and sampled earlier but not monitored regularly before the voluntary sampling began.)
Marshall	November 8, 2007	10 wells at 5 locations. All locations each had a shallow and a deep well.
Riverbend	December 16, 2008	14 wells at 7 locations. All locations each had a shallow and a deep well.

The Commission finds that the Company did not make reasonable or sufficient efforts to monitor for groundwater contamination until recently. This is evidenced by the fact that DEC more than tripled the number of wells from 2013

[47] Groundwater assessment at Allen also took place in the early 1980s, but the assessment was designed as a discrete study and not a long- term monitoring program.

to the present, and by the very limited number of wells the Company had installed before 2009. The insufficient attempts to conduct groundwater monitoring are persuasive evidence that the Company was not taking appropriate steps to achieve compliance with 2L regulations until after the Dan River spill and CAMA.

Furthermore, witness Wells mischaracterized witness Junis' testimony as saying that North Carolina's groundwater laws were intended to be punitive. (T 25 p 225) Witness Junis had testified that the 2L regulations were "effectively a strict liability – old impoundments were not exempted from the groundwater quality standards, and no showing of imprudence is required to establish a violation of 2L rules. That is, DEC had a duty to comply without regard to whether they followed accepted industry practices." (T 26 p 724) Nowhere does witness Junis state or imply that 2L is meant to be punitive.

Witness Wells testified that 2L is not punitive because DEQ has a practice of working with the permit holder to achieve corrective action rather than seeking to fine the permit holder. From this, he concluded that the groundwater laws are not intended to be used to deny cost recovery in utility rate cases. This analysis is misplaced for two reasons. First, 2L can be punitive in appropriate circumstances; the choice is up to DEQ. G.S. 143-215.6A allows DEQ to assess civil penalties and G.S. 143-215.6B allows criminal penalties for violations of the 2L groundwater standards. Second, and more importantly, whether 2L regulations are intended to be punitive, or not, is largely irrelevant to the question of equitable sharing in rate cases. The important consideration is whether DEC committed extensive coal ash-related environmental violations that required costly remediation, not whether DEQ pursued corrective action instead of fines.

In rebuttal testimony, witness Wells stated that “the numbers on Junis Exhibit No. 20 do not signify the number of groundwater violations, but rather the thoroughness of the evaluation.” (T 24 p 240) Witness Wells further states that groundwater monitoring is an iterative process. The Commission finds that part of the that iterative process and completing comprehensive site assessments involves installing a network of groundwater monitoring wells to define the plume of contamination and, thus, the number of violations shown in Junis Exhibit 20 demonstrates both the “thoroughness of the evaluation” now required by DEQ and CAMA and the extent and duration of the violations of the 2L groundwater standards on a site by site basis.

In his rebuttal testimony, in regard to the number of violations at DEC sites, witness Wells states:

> Measuring exceedances at different locations in the plume may result in multiple exceedances of groundwater standards, but it does not result in multiple violations of the prohibition in 15A NCAC 2L.0103(d). This distinction is important when evaluating Mr. Junis's claim that the number of exceedances is an indication of the "breadth of environmental violations."
>
> (T 24 p 240)

It should be noted, however, that DEQ has in the past interpreted each individual daily exceedance as a separate violation pursuant to the 2L rules. In 2015, DEQ used the “bookends method” to assess a $25 million fine for groundwater exceedances at the Sutton facility. (See Public Staff Wells Cross-Examination Exhibit 9 at pp 23-24) Junis Exhibit 20 does not calculate violations daily, but rather generally quarterly,[48] as reported by the Company. The number of violations would be much higher in Junis Exhibit 20 if daily exceedances were assumed.

The fact that DEQ chooses to pursue corrective action for exceedances at DEC sites, instead of fines, does not mean that there are no violations. 15A NCAC 2L.0106(e) provides that anyone responsible for an exceedance at or beyond the compliance boundary is required to provide DEQ with an assessment of the "violation" and required to submit a corrective action plan. Thus, the term "violation" is not dependent on DEQ seeking enforcement through a fine. By suggesting otherwise, DEC has improperly sought to diminish the appearance of the extent of its violations.

Essentially the same flaw appears in witness Wells' testimony that extraction wells would have been the "normal" course of CAMA and CCR Rule corrective action even without the Sutton settlement between DEC and DEQ. (T 24 p 241) This argument ignores the point that corrective action under CAMA, just as under 2L and the Sutton settlement resulting in the extraction wells at Belews Creek, depends on there being a groundwater violation to correct.

[48] Not all measurements reported in Junis 20 were taken quarterly. The data in Junis 20, however, is based on actual monitoring data as reported by DEC and does not assume daily exceedances between measurements.

Extraction wells may be "normal" corrective action under CAMA, but there is nothing normal about having groundwater violations that prompt the corrective action. The essence of witness Junis' recommendation to exclude the costs of extraction wells is that the cost is over and above what the CCR Rule and CAMA would have required in the absence of DEC's groundwater violations. If DEC had not contaminated the groundwater, the extraction wells would not have been necessary to comply with CAMA, CCR, or 2L.

Witness Wells also stated that witness Junis had suggested the amount of litigation against DEC suggested DEC was imprudent, and that such a suggestion was wrong. (T 24 pp 242-44) In fact, witness Junis did not suggest the amount of litigation indicated "imprudence." In connection with the Public Staff's equitable sharing proposal, rather than in an imprudence adjustment, he testified that the disallowance of litigation costs was due to the compelling evidence of environmental violations in DEQ reports of groundwater exceedances and the SOCs for unpermitted discharges. (T 26 pp 729-31) Witness Junis explained that a lawsuit by itself, or a settlement by itself, would not establish a violation.[49] (T 26

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[49] In their stipulation filed March 14, 2018, DEC and the Public Staff agreed to strike from witness Junis' direct testimony the following sentence located at page 718 of transcript volume 26: "In addition, it is my opinion that DEC's agreement to pay $5.98 million to settle the DEQ penalty proceeding regarding alleged NPDES and other surface water violations at the Dan River plant, and an additional $16,250 corresponding to five seeps identified in the March 4, 2016 NOV, is persuasive evidence of environmental violations notwithstanding DEC's denial of liability."

The correction was made because the position of the Public Staff is that litigation costs should be disallowed where there is a resolution of a lawsuit other than a finding of liability - such as a settlement - and there is also compelling evidence of environmental violations. This principle is discussed in further in witness Junis' testimony at T 26, pp 729-31, 737. Compelling evidence of DEC's violations can be found In DEQ reports on groundwater exceedances, the SOCs for unpermitted discharges, and the federal criminal plea agreement. See Junis Exhibit 33.

p 729) Instead, he determined that the Company's own groundwater monitoring data established that there were in fact groundwater violations to support the allegations in the legal claims against DEC. (Junis Exhibit 33)

Witness Wells sought to minimize the evidentiary importance of the coal ash environmental litigation by testifying that it was driven by non-governmental organizations (NGOs), implying that the type of plaintiff made the allegations less credible. (T 24 pp 21-22) The Commission does not agree with this analysis for two reasons. First, DEQ – not just environmental organizations – brought state court enforcement actions against every DEC coal-fired plant in North Carolina for coal ash-related environmental violations. DEQ may have been prompted by the NGOs' notices of intent to sue, but DEQ vigorously litigated those lawsuits against DEC until CAMA rendered them moot (Dan River and Riverbend), they were settled with an agreement to excavate (Buck),[50] or the case is ongoing (Allen, Marshall, Belews Creek, and Cliffside). The U.S. Department of Justice – not NGOs – also brought the criminal case for violations at the Dan River and Riverbend plants. Second, where lawsuits have been resolved without a finding that environmental violations either existed or did not exist, as happened for some of the state enforcement actions against DEC, the quality of the evidence supporting the allegations is what matters, not the identity of the plaintiff. As discussed earlier in connection with the Sutton penalty assessment settlement,

[50] The settlement to excavate Buck for beneficial reuse was between SELC and DEC. (T 26 p 706)

there was overwhelming evidence supporting allegations of groundwater violations at DEC plants. Junis Exhibit 20 demonstrates extensive groundwater violations at all seven DEC plants in North Carolina. The Commission agrees with DEC that the amount of litigation by itself is not evidence of violations; however, in this case, the amount of litigation corroborates the sampling data that shows compelling evidence of actual violations.

Witness Wells mischaracterized witness Junis' testimony as saying that any exceedance, no matter how minor or long ago, should lead to denial of cost recovery. (T 24 p 244) Again, the Company is setting up a false straw man. In testimony, witness Junis emphasized the large extent of violations. (See T 26 pp 648, 650; Junis Exhibit 20 showing 3091 groundwater violations) Witness Junis noted the duty to comply with environmental regulations: "the Company should not be able to claim that, in order to generate electricity, it had to create groundwater contamination and had no reasonable methods of prevention." (T 26 p 643) Witness Junis 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." (T 26 p 738; emphasis added) He then listed a wide range of circumstances in support of his position that the great extent of violations justified an equitable sharing. (T 26 pp 738-40) This was echoed by Public Staff witness Maness as one of his two general reasons for proposing equitable sharing: "the extent of the Company's failure to prevent environmental contamination from its coal ash impoundments, in violation of state and federal laws, supports ratemaking that leaves a large share of the costs for DEC shareholders to pay." (T 22 p 71; emphasis added)

Witness Wells continued his rebuttal by asserting that exceedances are normal, and not violations, where they occur at facilities built without liners, and that regulatory compliance is a matter of taking corrective action. He stated:

> 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 such impacts should be addressed in a measured process. Compliance with this process is not mismanagement and should not be held against the Company in the area of cost recovery.

(T 24 pp 245-46) It is true that the corrective action provisions of 2L are designed to address groundwater "impacts" (exceedances due to coal ash and not due to natural background levels). However, it is inaccurate to state "such impacts were not the result of regulatory noncompliance." The fact that there is an exceedance of 2L groundwater standards for regulated constituents, at or beyond the plant compliance boundary, and not due to natural background causes, means as a matter of law there is a violation. As discussed earlier, the 2L regulations expressly state that is so. The 2L regulations require prevention of groundwater contamination. The fact that they also provide for corrective action if prevention is not achieved, does not mean the prevention has been removed as a compliance requirement. The original language of the 2L rules, as promulgated in 1979, only prohibited the exceedance of groundwater quality standards. (AGO Wells Cross-Examination Exhibit 1) The revision to the 2L rules in 1983 added the corrective action provisions as an addition to, not a replacement of, the prevention requirement. The 2L rules as promulgated in 1979 and revised in 1983 did not exempt older facilities from compliance, but rather set up a larger compliance boundary of 500 feet for facilities permitted prior to December 30, 1983. Those permitted after that date were allowed a compliance boundary of 250 feet. (See Junis Exhibit 1)

Finally, witness Wells said witness Junis has implied that seeps at ash basins would have required basin closures. (T 24 pp 249-50) Once again, this is not what witness Junis said. Witness Junis observed that the DEQ state court enforcement actions involving the Dan River and Riverbend resulted in partial summary judgments on the grounds that closure under CAMA would remedy all the violations (including seeps and groundwater) alleged in the lawsuits. (T 26 pp 705-06) With respect to other types of violations, he stated:

> There will be cleanup costs associated with the admitted violations of G.S.143-215.1 and the Clean Water Act as evidenced by the recent SOCs requiring accelerated remediation of seeps. Those cleanup costs largely overlap CCR Rule and CAMA compliance costs because impoundment closure and possibly other corrective action under CAMA became the cleanup method. In the absence of CAMA, it is possible some other remedial action short of impoundment closure would have sufficed. However, given the existence of widespread environmental violations, we do know extensive corrective action would have been required to achieve compliance with pre-existing environmental laws and regulations.

(T 26 p 741) This is not to say the environmental violations would have necessarily required closure, but rather that closure under CAMA would provide a remedy for the environmental seeps. Of course, witness Junis also recognized that DEC's effort to obtain near term regulatory compliance for its unlawful seeps, prior to basin closures, involved seeking to include the seeps in its NPDES permit renewals, and where that was not possible, complying with an SOC to correct the seeps. (Id.) Thus, his testimony was quite different from saying the seeps would require basin closures.

In summary on the Public Staff's equitable sharing proposal, the Commission finds and concludes that:

A. There are extensive environmental violations resulting from DEC's failure to comply with groundwater and surface water regulations at all seven North Carolina DEC coal-fired plants, across a period of many years.[51] These violations include numerous unauthorized seeps that DEC has admitted, including DEQ penalties for some seeps, and 3,091 groundwater violations due to coal ash and not to naturally occurring background levels, confirmed by DEC's own groundwater monitoring data.

B. DEC has culpability for its environmental violations, even without a showing of traditional imprudence. The Company had a duty to comply with long-standing North Carolina environmental regulations; it failed that duty, and there are resultant costs. It would be manifestly unjust to require ratepayers to bear all the

[51] In addition, DEC entered a Consent Agreement with the South Carolina environmental regulatory department to remove coal ash from the W.S. Lee plant, which is the one South Carolina coal-fired plant on the DEC system.

deferred coal ash costs where those costs include corrective actions to remedy the Company's environmental violations.

C. Given the extensive environmental violations caused by DEC, and the impossibility of knowing the precise cost of remedying the environmental violation costs in the absence of CAMA and the CCR Rule, it is just and reasonable pursuant to G.S. 62-133(d) to achieve in rates an equitable sharing of deferred coal ash costs submitted for recovery in this proceeding. The equitable sharing applies only to deferred coal ash costs not otherwise disallowed in this Order.

D. An equitable sharing is independently justified by the uniqueness and magnitude of DEC's coal ash costs in this case.

E. A 49%-51% equitable sharing between ratepayers and shareholders, to be achieved by a 25-year amortization of deferred coal ash costs, with no return on the unamortized balance, is just and reasonable in the circumstances of this proceeding. The annual amortization expense appropriate for the Commission to approve in accordance with this conclusion is $18,882,000, as set forth in Public Staff Maness Late-Filed Exhibit 1.[52] When combined with the removal of the unamortized balance of deferred coal ash costs from rate base, the reduction in the Company-proposed revenue requirement related to deferred coal ash costs is approximately $120.4 million.

[52] As noted in that Exhibit, this amount is calculated by dividing $470,652,000 by 25 years, and then adding $56,000 to the result. The $56,000 represents additional carrying costs calculated by the Company that the Public Staff did not contest.

When combined together, the conclusions reached by the Commission herein regarding deferred coal ash costs, the "run rate," and coal-ash-reated legal expenses result in a revenue requirement reduction of approximately $323.0 million from that proposed by the Company.

[ALTERNATIVE IF THE COMMISSION DOES NOT ADOPT THE EQUITABLE SHARING PROPOSAL] 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. Some 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 nation. 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.

Since at least the 1980's, 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. At the same time, state and federal regulators have concluded, and addressed in legally binding water quality standards, that water soluble chemical constituents of coal ash should be limited to certain concentrations in groundwater and surface water due to toxic impacts.

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, failure to adequately maintain risers, improper maintenance of dikes, lax reporting, and violations of groundwater standards. 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. These two methods are where the vast majority of the billions of dollars of CCR remediation costs must be spent. These ultimate remediation steps are necessary to prevent leachate from infiltrating groundwater from the bottom of unlined basins. Some of these costs would have been required irrespective of the harms that constitute other alleged mismanagement; other remediation costs are the result of DEC's environmental violations. For example, the costs of extraction wells and treatment of the extracted water, and the potential future costs of excavating ash basins that could have been capped in the absence of groundwater violations, reflect incremental costs above CAMA and CCR Rule compliance. These incremental additional costs due to environmental violations are addressed elsewhere in this Order.

Apart from the disallowances for specific costs related to coal ash management, addressed elsewhere in this Order, it is not apparent that DEC's coal ash costs submitted for recovery in this proceeding are the result of traditional imprudence. DEC's use of unlined basins, and its delays in installing comprehensive groundwater monitoring for many years after the adoption of State 2L groundwater standards, were not violations of environmental regulations, nor were they inconsistent with practices of many other utilities.

Conversely, the Commission is unable to find DEC faultless in the dilemma it has faced. Much testimony addresses the issue of whether the Dan River spill and DEC's other 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 concludes that there is not any direct evidence DEC mismanagement is the primary cause of CAMA. 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 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 admitted to the federal court 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 arising primarily from the Company's admissions of mismanagement in the federal criminal case. Secondly, it supports the Commission's determination to reject the equitable sharing of coal ash costs as proposed by the Public Staff. The ultimate result of just and reasonable rates is served by a mismanagement penalty in lieu of an equitable sharing of coal ash costs.

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. G.S. 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, G.S. 62-2(a)(6). All companies are prohibited from violating environmental statutes. G.S 143-215.1. DEC is also 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 generation had been discontinued at the time of the 2014 spill. Inadequate oversight of impoundment dikes, unauthorized seeps from ash basins, and groundwater exceedances have not resulted in catastrophic failures that caused 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 persuasive 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 this an appropriate and sufficient penalty.

A major difficulty the Commission confronts in this case is the identification and quantification of the appropriate CCR remediation adjustment to incurred costs. For the most part, the record does not contain evidence appropriately quantifying the cost DEC incurred, due to environmental violations distinct from

CAMA and CCR Rule compliance, with respect to discrete remediation activities. The Commission deems disallowance of the totality of costs, as some parties advocate, unjustified. The Commission deems full recovery, as DEC advocates, 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 per G.S. 62-133(b)(4). State ex rel. Utils. Comm'n v. General Telephone Co., 285 N.C. 671, 208 S.E.2d 681 (1974). The only exception to this mandate is the limited discretion provided in G.S. 62-133(d). 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.[53] 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

[53] 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 …"

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.

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. This penalty is based on the totality of evidence contained in the record, as recited in detail above, and does not result in confiscation. This penalty is larger than the penalty ordered in Docket No. E-2, Sub 1142, for DEP because it reflects the proportionately greater penalty and remediation cost that DEC had in the federal criminal case. 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. 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, as DEC will still recover its reasonable costs and an overall return sufficient to finance safe and reliable electric service.

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, DEP 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 remediation costs incurred by DEC during the period rates approved in this case will be in effect shall be booked to a regulatory asset 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 or other lawful adjustment 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.

The Provisional Recovery Issue

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. (T 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. (T 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. (T 12 errata pp 156-39-40)

The Commission notes that provisional cost recovery is appropriate in certain circumstances. Where rates are put into effect, with notice that there may be a future refund to reflect a specified circumstance, the decision is not unlawful retroactive ratemaking. See State ex rel. Utils. Comm'n v. Nantahala Power & Light Co., 326 N.C. 190, 205 (1990). Indeed, in the DEP rate case (Docket No. E-2, Sub 1142), DEP stated that it would provide a future offset to customers for any insurance proceeds it wins in its claims against insurers on coal ash. DEC has not taken a different position in the present case. Moreover, the Commission has provided for provisional treatment of the federal corporate income tax changes in its January 3, 2018, order in Docket No. M-100, Sub 148. The pending lawsuits will establish whether past actions of DEC amount to environmental violations are likewise circumstances justifying provisional cost recovery.

Insurance Proceeds

Finally, the Commission finds and concludes that customers should benefit from any insurance proceeds recovered by DEC with regard to CCR remediation costs. DEP supported this position in its rate case in Docket No. E-2, Sub 1142, and the Commission ordered that result in the DEP case. While there was less discussion of the insurance litigation in the present case, DEC has not proposed a different position. In accord with the reasoning in our January 23, 2018, order in Docket No. E-2, Sub 1142, the Commission concludes that if DEC exercises reasonable care in representing its ratepayers' interests in the Insurance Case, then DEC should be entitled to receive its full authorized carrying charges on the deferred account. As stated above, if there is a meritorious issue raised about DEC's representation of the interests of its ratepayers in the Insurance Case, DEC shall bear the burden of proving that it took reasonable and prudent steps to obtain the maximum recovery. If DEC fails to meet this burden, the Commission can deny DEC carrying costs on that amount of insurance proceeds that were not recovered as a result of DEC's lack of reasonable and prudent efforts, or order other relief as appropriate.

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 FINDINGS OF FACT NOS. 75-76

The evidence supporting these findings of fact and conclusions is found in DEC'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.

In its Petition, DEP requests approval of its JRR, a five-year pilot program for industrial customers that is intended to curtail further loss of industrial jobs in DEP's service territory. (Petition, at 1.)

Company Witness Pirro testified that the Company had previously requested an Economic Recovery Rider for North Carolina manufacturers facing economic hardship in 2012. (T 19 p 89) Witness Pirro notes that although the State's economy has improved since 2012, manufacturing in the State continues to decline. (Id.) Since 2014, 53 manufacturing facilities served by Duke Energy have ceased operation in the State. (See Pirro Rebuttal Ex. No. 2) Witness Pirro states that the Company's Integrated Resource Plan filed in E-100, Sub 147 predicts a continued decline in industrial customers requiring service from the Company. (Id.)

Winess Pirro provides an overview of the eligibility requirements of the proposed JRR. In order to be eligible for the proposed JRR, the customer must do all of the following: (1) 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; (2) perform an energy audit within six months, or verify an energy audit has been performed within the past 36 months; (3) verify the customer is considering the ability to shift production from its facility, is considering a need to reduce employment at its facility due in part to the cost of electricity, intends to reduce production due in part to the impact of the cost of electricity, or the customer's load is otherwise at risk. (T 19 p 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 5) The Rider is not available for services under outdoor lighting schedules, for customers receiving discounts under an Economic Development Rider, for customers with an aggregate demand of less than 3,000 kW at all facilities operate by the Customer, and for facilities with less than 12 months of continued service. (Petition at 5)

In its Petition, the Company did not seek recovery of the revenue reduction resulting from implementation of the JRR at this time, but instead requested 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 3) The Company stated the annual revenue impact of the JRR would be $31.0 million. (Id.)

Public Staff witness McLawhorn testified that DEC's proposed JRR was filed in accordance with the JRT Order, and that the Company's proposed JRR is not unduly discriminatory and is in the public interest. (T 20 p 138) He stated that the JRR is designed to apply to large industrial customers and provides a balance of the benefits between the customers that will benefit from the rate reduction and the customers that will bear the costs of the reduction in revenues. (T 20 pp 138-39) Witness McLawhorn also stated that the Company demonstrated the need for the JRR in showing only slight growth in industrial sales after several years of decreasing sales to industrial customers. He testified that the proposed discounted revenue from the JRR participants would likely be greater than the marginal costs to serve participants. (T 20 p 139) Public Staff witness McLawhorn disagreed with the Company's proposal for deferral accounting of the discounted revenue. (T 20 p 146) The Public Staff proposed treating the revenue impact from the JRR in a rider that is reviewed and subject to adjustment annually, at the time of DEC's fuel adjustment. (T 20 p 147) The Public Staff also recommended that the DEC shareholders should be responsible for the first $4.5 million of the JRR for each year the rider is in effect.

CUCA witness O'Donnell testified in support of the Company's proposed JRR. Witness O'Donnell testified that if DEC were to lose its industrial load, the remaining DEC customers would see an increase in electricity costs of over 16% each year. (T 10 p 55). Witness O'Donnell concludes that the DEC residential customers are better off paying the small increase resulting from the JRR rather than the increase in costs that would result from the loss of industrial load in DEC's service territory. (Id at 56.)

CIFGUR witness Phillips supports the proposed JRR and testified that a healthy industrial base is important to the State. (T 26 p 280) Witness Phillips states DEC's Integrated Resource Plan shows growth in residential customers and a decline in the number of industrial customers. (T 26 p 281) Witness Phillips testifies that all customers benefit from the JRR, including customers that will not participate in the rider, because DEC will need to recover a great portion of its fixed costs from all other customers if industrial load is lost. (T 26 p 281) Witness Phillips testified in support for the inclusion of pipeline customers in the JRR, stating that pipeline customers are also important to the State's economy. (T 26 p 282). He also notes that CIGFUR's proposed definition for customer eligibility in the Commission's Order Adopting Guidelines for Job Retention Tariffs (JRT Order) adopted in Docket No. E-100, Sub 73, contained the phrase that included pipeline customers, and the Commission was supportive of CIGFUR's proposed definition. (T 26 p 282)

Commercial Group witnesses Chriss and Rosa recommend the Commission reject the JRR as it is proposed, and recommend any approved JRR should not discriminate against non-industrial ratepayers and be narrowly tailored to provide subsidies to targeted ratepayers. (T 26 p 529) The Commercial Group witnesses also testified that it is unclear from the Petition "how much rigor will be applied to the customer attestations regarding is operations." (T 26 p 546)

In the Stipulation, the Company and the Public Staff agreed that the JRR meets the JRT Guidelines adopted in the JRT Order, notwithstanding two areas of disagreement: whether pipeline customers should be eligible and whether the Company shareholders would contribute $4.5 million to the JRR recovery on an annual or one-time basis. The Stipulating Parties also agreed that the JRR-related revenue loss would be recovered through a rider from all retail customers, subject to annual adjustment at the same time as DEC's September fuel adjustment. The Parties further agreed the Company shall filed compliance tariffs prior to the implementation of the JRR and notify customers by bill insert when the rider is implemented.

<u>Pipeline Eligibility</u>

DEC's proposed JRR provides, in part, that the JRR be available for customers that "use electric power as the 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."

Public Staff witness McLawhorn expressed concern in his testimony regarding DEP's proposal to extend eligibility for the JRR to companies involved in the "transportation or preservation of a raw material or a finished product." (T 20 p 141) The Public Staff understood this phrase to refer to pipelines including natural gas pipelines. Witness McLawhorn noted that gas pipelines are different from other manufacturing facilities in that pipelines are fixed investments that are not easily relocated, and unlike other industrial manufacturers, pipelines do not produce a finished product. (T 20 p 142) He recommended this disputed phrase be eliminated from the eligibility criteria of the JRR. (Id.)

DEC witness Pirro testified in his rebuttal testimony that while the disputed phase could apply to pipeline customers, it could also apply to other customers. (T 19 p 92) He stated that the Company believes it is appropriate to include pipeline customers in the availability of the JRR because these customers have expressed concerns with electricity costs. (Id.)

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 or a finished product” should be removed from the eligibility criteria.

Cost Sharing

In its JRR Petition, DEC proposed that it absorb $4.5 million of the revenue loss from the JRR on a one-time basis. The Public Staff proposed that the Company contribute $4.5 million on an annual rather than one-time basis.

Public Staff witness McLawhorn testified that not only customers, but shareholders, benefit from the retention of industrial jobs and the load associated with the jobs. Therefore, a fair sharing of the revenue impact of the JRR would require the Company to contribute $4.5 million on an annual rather than one-time basis.

The Company, as well as ratepayers, benefit from the retention of industrial jobs, and the load related to the retention of the industrial jobs. It is appropriate for the Company to contribute to the JRR on an on-going basis, rather than making a one-time contribution.

Commission approval of the JRR is largely a question of public policy requiring the Commission to balance the costs and benefits to the company’s ratepayers. Because the JRR benefits both ratepayers and shareholders, the Commission finds that in order to achieve just and reasonable rates, an equitable sharing of JRR-related revenue loss should be a part of any JRR-related revenue loss recovery rider. Therefore, the Company's revenue loss recovery should be reduced by $4.5 million each year the JRR is in effect to recognize the benefit to shareholders of the JRR.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 77-79

The evidence supporting these findings of fact and conclusions is found in DEC's verified Application, the testimony of Company witness Pirro, the testimony of Public Staff witness Floyd, the testimony of other witnesses, the exhibits of witness Pirro, and the entire record in this proceeding.

DEC has requested that the BFC for its rate classes be increased to better recover the cost of serving customers regardless of the customer's level of usage (T19 p 60). The Company proposes to increase the monthly residential BFC from $11.80 to $17.79. Witness Pirro states that the Company's cost of service analysis supports increasing the residential BFC to $23.78, but that the company has requested a smaller increase to moderate the effect of the increase in the BFC on low usage customers. (Id.) Witness Pirro also proposed changes to the BFCs for other major customer classes based on the customer-related costs to serve those classes. (T19 p 63) Witness Pirro's Direct Exhibit 8 provides the theoretical BFC for these classes, which is calculated by the Company to reflect the customer-related costs. The exhibit also shows the calculated BFC, which is the new BFC proposed for each class.

Public Staff witness Floyd testified that DEC's requested increase is unreasonable given the impact of a large increase on low usage customers. (T 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 recommended that any increase in the residential BFC should be limited to 25% of the revenue increase assigned to that customer class. (T 23 p 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. (T 23 p 65)

Several other intervenors provided testimony regarding the Company's proposed increases to the BFCs. Witness Barnes, as well as NC Justice Center witness Wallach, also assert that an increase in the customer charge dilutes customer incentives for distributed generation and energy efficiency. (Barnes T 20 p 71; Wallach T 8 p 73) The Commission gives significant weight to witness Pirro's rebuttal testimony in response to this argument. Witness Pirro explained that "[f]ailing to properly recover customer-related costs via a fixed monthly charge provides an inappropriate price signal to customers and fails to adequately reflect cost causation." (T 19, p 85) In addition, he testified that shifting fixed customer-related cost to the volumetric energy rate exacerbates this concern and over-compensates energy efficiency and distributed generation for the cost avoided by their actions. (Id.) Further, the Commission determines that existing energy efficiency programs are effective, and it is not persuaded that it needs to further support energy efficiency by refusing to approve an appropriate increase in the BFC.

Witness Deberry also opposed the increased residential BFC, testifying that it will affect already cost-burdened residents who struggle to afford housing costs. (T 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. (T 26 p 352) 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. (T 26 p 352) Similarly, witness Howat testified that increasing fixed customer charges causes disproportionate impacts to low-volume, low-income customers and discourages energy efficiency. (T 8 p 29) 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, and the increased threat of disconnection posed by the Company's rate increase proposes a threat to the health and safety of these customers and the larger community. (T 8 pp 31-35)

In his rebuttal testimony, Company witness Pirro responded to the arguments raised by these intervenors regarding the proposed increases to the BFCs. (T 19 p 83) 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." (T 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 witness Wallach's assertion, actually results in high-usage customers subsidizing the rates of lower-usage customers. (Id.)

Witness Pirro also noted that the Company has carefully examined its costs and identified customer-related costs in order to determine the proposed BFCs, and that other utilities' costs and rates are not relevant to the determination of DEC's rates. (T 19 p 84) Witness Pirro rebutted witnesses Barnes' and Wallach's argument that the BFC discourages distributed generation and energy efficiency. (T 19 p 85) Witness Pirro stated 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. Shifting customer-related costs to the kWh energy rate further exacerbates this concern and over-compensates energy efficiency and distributed generation for the cost avoided by their actions. (T 19 p 85) DEC witness Pirro also testified that the Company is mindful of the impact of the rate increase on its low-income customers, but the Company must design rates based on cost causation. (T 19 p 85) Witness Pirro makes clear, however, that contrary to the assertions of witnesses Howat and Deberry, he believes that biasing rate design is not the most effective way to address the financial needs of low income customers. (T 19 p 85) Instead, there are Company, state, and federal programs which are designed to aid low-income customers. (T 19 p 85) For example, the Company offers the Residential Income Qualified Energy Efficiency and Weatherization Assistance Program and various payment plans to assist low-income customers. (T 19 pp 85-86) DEC also promotes the Energy Neighbor Fund, which raises funds for local aid agencies to assist low-income customers. (T 19 p 86)

The Commission concludes that limiting the increase in the BFCs to no more than 25% of the revenue increase assigned to a customer class is just and reasonable and strikes an appropriate balance that provides rates that more clearly reflect actual cost causation and, thus, minimize subsidization and provide proper price signals to customers in the rate class, while also moderating the impact of such increase on low-usage customers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 80-82

The evidence in support of these findings of fact and conclusions is found in the testimony of DEC witnesses McManeus and Pirro and Public Staff witness Saillor.

Witness Pirro's direct testimony presented the Company's adjustments to per book sales and revenues related to customer growth for the 12-month test period ending December 31, 2016. (T 19 p 52) Form E-1, Item 10, Adjustment NC-0400 (Adjustment NC-0400), filed with the Company's original application, shows that witness Pirro's revenue adjustment was $13,480,000 based on an adjustment of 133,348,620 kWh of additional sales.

The supplemental testimony of witness McManeus included revisions to the Company's customer growth adjustment in which the Company extended the revenue adjustment to reflect customer growth through December 31, 2017. Witness McManeus also testified to the addition of a usage adjustment to account for a drop in average sales per customer in the residential rate class. (T 6 p 295) The Company filed a supplemental Adjustment NC-0400 that changed the adjustment from a positive revenue adjustment to a negative adjustment of $17,962,000 based on decreased sales of 137,941,752 kWh.

Witness Saillor filed testimony and exhibits supporting the Public Staff's revenue adjustment for customer growth and usage for the test period. His analysis was extended through November 30, 2017 in his direct testimony and then through December 31, 2017 in supplemental testimony. Witness Saillor used a method for his adjustment that was similar to the Company's method, including the use of regression analysis to find an end-of-period level of customers for the Residential, Miscellaneous and Lighting rate classes, and a customer-by-customer approach to analyze new and closed accounts for Commercial and Industrial customers. Witness Saillor's method for calculating customer growth was consistent with the method approved by the Commission for use in the Company's most recent fuel case. (T 26 pp 900-02)

Witness Saillor described several refinements to the Company's adjustment process that he incorporated into his adjustment. First, the customer growth and usage adjustments related to residential customers were calculated using weather-normalized sales data. Second, he calculated a test period usage adjustment for the residential rate class to account for the change in usage that occurred during months that were within the test period. Third, for new customer accounts reviewed in the customer-by-customer approach, witness Saillor altered the method for calculating the new customer's average monthly usage to more accurately estimate monthly unrealized sales added to the test period. His adjustment amounted to a revenue increase of $16,308,523, based on an adjustment of 156,057,311 kWh of additional sales. (T 26 pp 902-07; T 26 pp 911-17)

Witness Pirro stated in his rebuttal testimony that the Company objects to several of the modifications included in witness Saillor's adjustment for the Public Staff. (T 19 p 98) He disagreed with the Public Staff's inclusion of a usage adjustment for the test period. He also stated that a "detrending" scheme should not be used when calculating the usage adjustment, referring to the Public Staff's initial adjustment through November 2017.[54] He argued for removing more than 12 months of sales associated with accounts closed during the extended period in the customer-by-customer approach. Finally, witness Pirro argued that the

[54] The usage adjustments for the update period from January 2017 through December 2017 for both the Company and Public Staff were based on the difference between the 12 months ended December 31, 2017, and the 12 months of the test period.

adjustment should be updated through the end of December 2017. He indicated that the Company does agree with using weather-normalized sales to calculate the residential adjustments for customer growth and usage. (T 19 pp 99-101) The Company's final adjustment to per-books sales and revenues related to customer growth and usage amounted to a positive adjustment of $16,982,000, based on increased sales of 153,364,350 kWh, as shown in his rebuttal exhibits and those of witness McManeus.

In the Commission's judgment, witness Saillor's calculations for the usage adjustment are more appropriate than witness Pirro's for use in this proceeding. The primary purpose of a usage adjustment is to ensure that the calculation of revenues is based on actual trends in customer usage, rather than on short-term aberrations – either upward or downward – in usage. These trends should be based on the difference in two 12-month periods of time to account for seasonal usage patterns, and the adjustment should address the change in usage for the entire period being considered – in this case the test period from January 2016 through December 2016 and the update period from January 2017 through December 2017. Witness Saillor's usage adjustment is more consistent with these principles than that of witness Pirro. Witness Pirro's usage adjustment only adjusts for the change in usage during the 12 months of the extended period (January 2017 – December 2017) and fails to account for the change in usage for the 12 months of the test period. And, because his adjustment does not adjust for usage during the test period, the Company's proposed methodology cannot be used to normalize test period sales for usage in the Company's annual fuel rider proceedings, which has been shown in this proceeding to result in a material change to test period revenues.

Witness Pirro was emphatic that only data from the test year and the year following it (in this case, 2016 and 2017) could be used in making adjustments for change in usage per customer, and the use of data from the year preceding the test year (in this case, 2015) was inappropriate. (T 19 p 229) He acknowledged, however, that the purpose of adjustments to usage per customer is to determine whether usage in the test year was abnormally high or low and, thus, should be modified for use in calculating rates for future years. (T 19 p 230) In the Commission's view, any adjustment, whether it uses data from the preceding or the following year, is appropriate if it helps the Commission determine whether the usage per customer in the test year was atypical as compared with usage in the preceding and subsequent years.

Moreover, witness Pirro's argument that data from the year preceding the test year cannot be used in a usage adjustment could not be applied in a fuel adjustment proceeding. As he acknowledged (T 20 p 13), the test year for DEC's next fuel adjustment case[55] will be the calendar year 2018. There will be virtually no data from the year 2019 available in March; for the Company to make a usage adjustment, it will have to turn to data from the year preceding 2018, but witness Pirro has ruled that out.

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[55] In other words, the next case after the 2018 fuel case, which is currently in progress.

Additionally, the Commission notes that if usage was higher in the test year than in either the preceding or the following year, this would at least suggest the possibility that the high usage in the test year was atypical, and witness Pirro appeared to acknowledge this. (T 20 p 15) Yet under witness Pirro's principle of excluding data from the year preceding the test year, this possibility could not be considered.

The Commission also believes witness Saillor's calculations for the customer growth adjustment are more appropriate than witness Pirro's for use in this proceeding. The purpose of the customer growth adjustment is to estimate the total kWh sales the Company would have booked had the end-of-period level of customers been served for the entire 12 months of the test period. In the case of the customer by customer approach, for new accounts, kWh sales are added at the customer's monthly average usage rate for each month of the test period the account was not active, and test period sales are removed for closed accounts. In addressing the customer growth calculations for customers in the Commercial and Industrial classes, where both witnesses used a customer-by-customer analysis rather than a regression analysis, witness Pirro contended that witness Saillor erred in adding 12 months of test period sales for new accounts added during the extended period, while removing 12 months of test period sales of the customers that left the system during the extended period. Witness Pirro proposed instead to remove more than 12 months of sales from the test period for closed accounts. (T 19 p 100) Witness Pirro's adjustment does not follow the principal that the customer growth adjustment should estimate the change in sales the Company would have booked had the end of period level of customers been served for the entire twelve months of the test year. His adjustment improperly adds and removes kWh sales from outside the test period. Witness Saillor's method correctly considers the customer growth associated with each new and closed account by adding 12 months of sales to the test period or removing 12 months of sales from the test period, respectively.

For the reasons discussed above, the Commission finds and concludes that the Public Staff's methodology for calculating customer growth and usage is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 83-86

The evidence in support of these findings of fact and conclusions is contained in the testimony of Company witnesses De May, Fountain and McManeus, the testimony of the various intervenors, the testimony of Public Staff witness Boswell, and the entire record in this proceeding.

On December 22, 2017, the Tax Act was signed into law. Among other provisions, the Tax Act reduced the federal corporate income tax rate from 35% to 21%, effective January 1, 2018.[56] It also repealed the manufacturing tax deduction and eliminated bonus depreciation.

[56] In response to the enactment of the Tax Act, on January 3, 2018, the Commission opened a rulemaking docket (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

The reduction in the corporate income tax rate in the Tax Act results in Federal EDIT for utilities. ADIT occurs because of timing differences between when a utility collects income taxes from ratepayers and when those taxes are paid to the Internal Revenue Service. One of the major types of ADIT arises from differing annual depreciation rates applied to the cost of assets purchased by a utility or other business. Under generally accepted accounting principles (and, in many cases, under the regulatory accounting principles followed by this Commission), a utility business is allowed to record on its books an annual expense representing the allocation of the cost of an item of property between its acquisition and the end of its useful life, and determine the income tax expense recovered annually from its ratepayers on that basis. However, the expense is in most cases determined by the "straight line" method; that is, evenly over each year of the property item's life. In contrast, the Internal Revenue Code (IRC) allows accelerated depreciation for purposes of income tax determination: the business may deduct from its income, on its tax returns, a larger proportion of the property's value in the initial years of its life and a smaller percentage in the later years.

For accounting and ratemaking purposes, the temporary tax savings that a utility obtains by using accelerated rather than straight-line depreciation for income tax purposes is treated as a deferred tax liability. The total amount of taxes a utility has been able to defer, at any given time, is classified as ADIT. ADIT is treated as

existing rates and charges, effective January 1, 2018, will be billed and collected on a provisional rate basis.

cost-free capital and is deducted from rate base, because the source of the funds that have not yet been paid to the IRS is the ratepayer. If the income tax rate remains constant, the increased taxes a utility pays in the later years of a property item's life will be equal to the tax benefit of accelerated depreciation received by the utility in the earlier years (but not flowed through to the ratepayers) in the earlier years); and, if the time value of money is disregarded, the total taxes the utility pays, with respect to that property item, will not be increased or reduced by the use of accelerated depreciation.

When the federal income tax rate is reduced, as it was in the Tax Act, a portion of the ADIT that the utility has accumulated from the ratepayers will never be needed by the utility for the payment of taxes. This portion is classified as Federal EDIT. The IRC requires that certain EDIT must be normalized, or flowed back subject to certain limitations. Federal EDIT that is subject to this limitation is classified as "protected" Federal EDIT. All other types of Federal EDIT are termed "unprotected," in that there are no limitations placed upon them by the IRS with regard to the length of time over which they can be returned to ratepayers.

In her Second Supplemental Direct Testimony filed January 16, 2018, DEC witness McManeus 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 corporate tax rate, nor did it include any proposal for the return of the protected and unprotected Federal EDIT to ratepayers. (T 6 p 299)

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 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 flowback of Federal EDIT.

Intervenor witnesses Coughlan (NCLM), Higgins (Kroger), and Phillips (CIGFUR III) likewise advocated for an immediate reduction in the Company's revenue requirement as a result of the federal income tax reduction in the Tax Act.

In rebuttal filed on February 6, 2018, the Company opposed an immediate reduction in the Company's revenue requirement to account for the reduction in the federal income tax rate and offered no proposal to return Federal EDIT to ratepayers. Company witness Fountain testified that the Company believed 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." (T 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. (T 6 p 213)

In her rebuttal testimony, witness McManeus testified that the Company opposed witness Boswell's adjustment to reduce income tax expense. (T 6 p 323) She testified that the Company has 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. She 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. (T 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. She included three adjustments based on the information that had been 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 IRC. For unprotected Federal EDIT, she 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, refunding the unprotected Federal EDIT over two years allows the Company to properly plan for any future credit needs. (T 26 pp 618-19)

On the first day of the evidentiary hearing, the Company presented its proposal to flow back the effects of the Tax Act to ratepayers in an attachment to the summary of Company witness De May.[57] Under the Company's proposal, income tax expense would be reduced to reflect the decrease in the income tax rate; protected Federal EDIT would be flowed back over the life of the assets; unprotected Federal EDIT related to plant, property and equipment (PP&E) would be flowed back over twenty years; other unprotected Federal EDIT would be flowed back through a rider over five years; and the Company would collect an offset of $200 million through acceleration of certain expenses. (T 4 pp 423-24) He testified that the purpose of the $200 million was to help restore to the Company some of the cash flow lost as a result of implementing rate reductions related to the Tax Act, and was intended to restore the Company's balance sheet to pre-Tax Act levels. (T 4 p 444) The Company's proposal as described by witness De May was reflected in McManeus Stipulation Exhibit 1 Updated for Hearing. (T 6 p 359; T 10 pp 236-44)

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. (T 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). (T 6 p 399) She further admitted that because

[57] The attachment was a filing made by the Company on March 1, 2018 in the Tax Docket.

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. (T 8 p 224) She agreed that due to the reduction of the tax rate, the Federal EDIT is no longer needed to cover the Company's taxes. (T 8 p 224) She acknowledged that the $200 million in accelerated expenses would be included in the Company's revenue requirement. (T 8 p 226) When asked to identify the specific assets and other items 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. (T 8 p 230) Witness Fountain conceded that he could understand the positon of some customers who would like to have the benefits of the federal tax reform all flowed back immediately, but stated he believed the Company's proposal is balanced. (T 7 p 94)

In response to Commission questions about the Company's income tax proposal, witness McManeus testified regarding the accelerated expenses that the $200 million was provided by witness De May as an appropriate number to accomplish the objectives that he had in mind. There are no specific numbers that make up the $200 million. (T 9 p 38) Witness Fountain could not identify any specific regulatory assets the Commission might select for accelerated amortization. (T 9 p 90) He acknowledged that the Company is merely trying to achieve a particular financial metric for its cash flow. (T 9 p 90)

On March 19, 2018, Public Staff witness Boswell filed 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 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. (T 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. (T 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. (T 26 p 636)

Witness Boswell contended that the Company has artificially created two categories of unprotected Federal EDIT for purposes of its proposal: "unprotected PP&E" and "unprotected other". She explained that the tax normalization rules are very clear – either Federal EDIT is protected, or it is not. The Federal EDIT that the Company designates as "PPE-related" is still clearly unprotected, a fact conceded by the Company. The Company's assertion that it should only return this PP&E-related unprotected Federal EDIT over approximately the same period of time it would have paid the funds to the IRS had the Tax Act not 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. Witness Boswell asserted that these funds rightfully belong to the ratepayers and should be returned to them as soon as reasonably possible. She further noted that the Company will continue to collect ADIT at a tax rate sufficient to meet its tax obligations. (T 26 pp 635-36)

Witness Boswell further testified that the Public Staff has provided the Company with the benefit of removing the total amount of the unprotected Federal EDIT credit from rate base in the current case, thus providing the Company with an increase in rates to moderate any cash flow issues, to the extent they would exist. The financing cost to the Company will be imposed ratably over the period that the Federal EDIT is returned through the levelized rider. (T 26 p 637)

Witness Boswell stated that while the Public Staff believes it would be reasonable for the Commission to order a refund of unprotected Federal EDIT through a two-year rider (the Public Staff's original proposal), the Public Staff believes that a five-year rider falls within the range of reasonableness in this case. She stated that the Public Staff modified its position because the Public Staff believes that a five-year period would increase rate stability for ratepayers during the flowback period and result in a significantly smaller increase after the rider expires. Additionally, the levelized rider would include a return, thus ensuring that ratepayers are made whole despite the additional three years. (T 26 pp 637-38)

Finally, witness Boswell addressed the Company's recommended increase in revenue requirement of $200 million as part of the Company's tax proposal. She testified that the Public Staff adamantly opposes this part of the Company's proposal. She asserted that the proposed $200 million increase in revenue requirement eliminates virtually the entire benefit of the tax rate reduction for current ratepayers and delays flowing the benefit through to ratepayers for an unknown period of time. The reduction in the federal tax rate is an undisputed cost of service component reduction from which ratepayers should benefit. Making the timely flowback of any ratepayer money due to the reduction of income tax rates contingent upon the Company receiving $200 million per year in additional revenue requirement is unacceptable. (T 26 p 639)

Witness Boswell noted that the Company has provided no details or supporting information as to what time period the accelerated depreciation would occur. In addition, the Company has not provided details or supporting information regarding the future expenses the Company would offset (other than legacy meters), thus rendering them mostly unknown and unmeasurable at this time. Additionally, the Company has failed to produce any evidence offering rational support for changing the depreciation rates of any of its assets. She stated that this leads the Public Staff to conclude that the $200 million is merely a number chosen by the Company to offset the revenue requirement impact of the tax decrease. Witness Boswell explained that depreciation expense is the result of depreciation rates established through complex depreciation studies, approved or adopted by the Commission, the purpose of which is to spread the cost of depreciable assets fairly and reasonably over the assets' lives, and thus to the generations of ratepayers served by the assets. Departing from this transparent process in the course of a general rate case simply to delay flowing through the benefit of reductions in an entirely separate category of costs (income taxes) is neither fair nor reasonable. She stated that the Public Staff believes offsetting known and measurable reductions in taxes to be paid going forward against either unknown future coal ash basin costs or acceleration of depreciation previously approved by the Commission in order to delay refunding ratepayer money presents significant intergenerational issues and constitutes inappropriate ratemaking. (T 26 pp 639-40)

The Supplemental Testimony of Tech Customer witnesses Brown-Hruska and Strunk addressed DEC's proposed rationale for the $200 million increase in revenue requirement and presented testimony showing that DEC's rationale is inconsistent with the financial forecasts that it provided in DEC's own exhibits.[58]

On further cross examination of Company witness McManeus, two exhibits relating to the 1986 federal income tax reduction (the Tax Reform Act of 1986, or TRA-86) were stipulated into the record and entered into evidence[59]. The first document was the Company's application dated November 13, 1987 in Docket No. E-7, Sub 415, which showed that in that case, the Company did not propose to create two separate classifications of unprotected Federal EDIT, but simply proposed to refund all its unprotected Federal EDIT through amortization over a five-year period. The second document was a copy of the Commission's Order Allowing Rates to Become Effective in Docket Nos. E-7, Sub 415 and M-100, Sub 113, in which the Commission approved the Company's application.

The Commission's primary concern regarding the effects of the Tax Act is to ensure that ratepayers receive the full benefit of the reduction of the federal corporate income tax rate. Rates have been set to ensure that the Company has adequate funds with which to pay taxes; now that the federal income tax rate is reduced, rates should be adjusted accordingly. The question before the

[58] The Commission's findings and conclusions regarding the effects of the Tax Act on the Company's financial credit metrics are discussed elsewhere in this Order.

[59] These documents were filed in the docket on March 23, 2018.

Commission is how, and over what length of time, these effects should be implemented.

The evidence shows that there is some agreement 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.

Additionally, the Company and the Public Staff agree, and no one disputes, that protected Federal EDIT, which is subject to tax normalization rules, should not be returned to ratepayers any faster than allowed under the IRC rules. Therefore, the Commission finds and concludes that it is appropriate for the Company to return protected Federal EDIT in the amount, and over the time period, recommended by the Company and the Public Staff.

The differences between the parties regarding the effects of the Tax Act relate to how, and in what manner, to return unprotected Federal EDIT to ratepayers and whether the Company's revenue requirement should be increased by $200 million to offset the impacts of the Tax Act on the Company's cash flow. On these issues, the Commission is in agreement with the Public Staff.

Regarding unprotected Federal EDIT, the Company has created an artificial category of "unprotected PP&E" in an effort to justify longer retention of Federal EDIT that is currently owed to ratepayers. This artificial category is not grounded in law or logic. The evidence shows there is nothing in the IRS regulations to suggest that Federal EDIT that has some characteristics of PP&E, but is unprotected, should be treated differently from other unprotected Federal EDIT. Had Congress intended such EDIT to be treated differently from other unprotected Federal EDIT, it would have stated so in the legislation; however, it did not. Instead, Congress designated that portion of Federal EDIT as unprotected. The Company concedes that Federal EDIT is either protected by IRS normalization rules or it is not. In fact, the Company's choice of the name "unprotected PP&E" underscores the fact that it is <u>unprotected and thus not subject to the flowback restrictions of protected PP&E.</u>

The Commission agrees with the Public Staff that the Company's assertion that it should only return this PP&E-related unprotected Federal EDIT over the same general period of time it would have paid the funds to the IRS had the Tax Act not passed is not supportable by any logical accounting or ratemaking principle. Thus, the Company's artificial categorization has no impact on this Commission's decision regarding the reasonable amount of time within which to return these funds to ratepayers. The Commission concludes that the Company's proposal to "carve out" some of the unprotected Federal EDIT and delay return of the funds simply because the funds are similar to the protected Federal EDIT is unreasonable and should be rejected.

Through the years, the Commission has set rates at a level to ensure that the Company would be able to pay its taxes, including deferred taxes, when they came due.[60] These funds were paid by ratepayers to the Company to enable the Company to pay its taxes; now that the funds are no longer needed to pay the Company's taxes, they should be flowed back to ratepayers as quickly as practicable. The fact that the Company has enjoyed the use of these funds as cost-free capital does not change the fact that it is ultimately customer money that is no longer needed for tax payments. The only remaining question is over what period of time the refund should occur.

The Commission has carefully considered the evidence as to the appropriate time period over which to return unprotected Federal EDIT. The Commission is not persuaded that because 81% of the unprotected Federal EDIT "relates" to plant, property, and equipment, they should be returned to ratepayers over the same general time period as protected Federal EDIT. While the Company may have had an expectation before the tax rate change that it would have access to these funds for the life of the assets to which they are related, the Commission finds that expectation to be unreasonable in light of the evidence presented. The Company no longer needs these funds to pay its taxes, which is why they were collected from ratepayers in the first place. It is disingenuous for the Company to

[60] The Commission notes that the last reduction in the corporate income tax rate occurred in 1986. The evidence in the record shows that the Company in that instance did not propose to create two separate classifications of unprotected EDIT, but simply refunded all its unprotected EDIT through amortization over a five-year period.

contend (as it has on other issues) that it must recover its costs as quickly as possible, while at the same time arguing that customers should wait to receive money that is rightly owed to them.

The Commission disagrees with the Company's assertion that it is more beneficial for customers if the Company retains this money as a source of cost free capital. The Company is adequately financed and its access to low cost debt is more than sufficient to offset the loss of these funds. Any speculative, incremental increase in debt costs associated with the replacement of these funds is insignificant to the value of the actual money returned to customers. While the Company seeks to maximize its cash flow for its benefit, it is logical that the Public Staff would seek a similar result on the behalf of ratepayers.

The Commission finds and concludes that the Public Staff's proposal to return unprotected Federal EDIT over a five-year period through a rider to be reasonable; it appropriately balances the interests of ratepayers and the Company. As discussed elsewhere in this Order, flowing the unprotected Federal EDIT over five years as recommended by the Public Staff will not unreasonably negatively affect the credit metrics and cash flow of the Company. By removing the total amount of the unprotected Federal EDIT credit from rate base in the current case, the Company will be provided with an increase in rates to moderate any cash flow issues, to the extent they would exist. Further, while a two-year flowback as originally proposed by the Public Staff might have resulted in a significant rate increase after two years, a five-year flowback greatly reduces the impact on rates upon the expiration of the rider. The five-year flowback also helps to offset deferred costs that the Commission has allowed the Company to recover over similar time periods.

Finally, 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. As pointed out by the Public Staff, 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. Moreover, the request was not time-limited; in theory, the additional $200 million in revenue requirement would equate to $1 billion after five years. Finally, offsetting known and measurable reductions in taxes to be paid going forward against either unknown future coal ash basin costs or acceleration of depreciation previously approved by the Commission in order to delay refunding ratepayer money presents significant intergenerational issues and constitutes inappropriate ratemaking.

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 strongly rejects this proposal as arbitrary and unfair to ratepayers. The revenue requirement approved in this Order, without the additional $200 million, is fully sufficient to enable the Company to provide adequate service to its ratepayers and earn a reasonable return for its investors. The Company has demonstrated through the years, during both strong and weak economic times, that it is capable of managing its finances. The Commission does not believe that the tax rate reduction and EDIT flowback impairs this capability and 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 is not supported by the preponderance of the evidence and is not approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 87

The evidence supporting this finding of fact and conclusions is found in the testimony of DEC witness De May, Public Staff witnesses Parcell and Hinton, AGO witness Woolridge, and Tech Customers witnesses Strunk and Brown-Hruska, and the entire record in this proceeding.

DEC witness De May testified in his direct testimony that financial strength and access to capital are necessary for DEC to provide cost-effective, safe, environmentally-compliant, and reliable service to its customers. He testified that one of the specific objectives is maintaining sufficient cash flows to meet obligations. (T 4 p 37) To assure reliable and cost-effective service, and to fulfill its obligations to serve customers, DEC must continuously plan and execute major capital projects. He testified strong investment-grade credit ratings provide DEC with greater assurance of continued access to the capital markets on reasonable terms during periods of volatility. (Id. at 38)

Witness De May testified that creditworthiness is a term used to describe a company's overall financial health and its willingness and ability to repay all financial obligations in full and on time. An assessment of DEC's creditworthiness is performed by two major credit rating agencies, S&P and Moody's, and results in DEC's credit rating and financial outlook. (Id. at 39)

DEC witness De May testified that many qualitative and quantitative factors go in this creditworthiness assessment. Qualitative aspects may include DEC's regulatory climate, its track record for delivering on its commitments, the strength of its management team, its operating performance, and the strength of its service area. Quantitative measures are primarily based on operating cash flow and focus on the level at which DEC maintains debt leverage in relation to its generation of cash and its ability to meet its fixed obligations (interest expense in particular) on the basis of internally-generated cash. The percentage of debt to total capital is another example of a quantitative measure. (Id. at 39) Witness De May testified that DEC's outstanding debt is rated as follows:

Rating Agency	S&P	Moody's
Issuer / Corporate Credit Rating	A-	A1
Senior Secured	A	Aa2
Outlook	Stable	Stable

He further testified that obligations carrying a credit rating in the "A" category are considered strong, investment-grade securities subject to low credit risk for the investor. He testified that an "A" rated debt is presumed to be somewhat susceptible to changes in circumstances and economic conditions; however, the debt issuer's capacity to meet its financial commitments is considered strong. (Id. at 41.)

With respect to the Tax Act, in his rebuttal testimony, DEC witness De May stated that the Commission should take into account other, non-tax impacts of the legislation, particularly as it relates to cash flow. He testified that this was highlighted by Moody's in an article it published on January 24, 2018,[61] which notes (at p. 2) that "For the investor-owned utilities sector, the 2017 tax reform legislation will have an overall negative credit impact on operating companies and their holding companies." Moody's estimates that the Tax Act "will dilute a utility's ratio of cash flow before changes in working capital to debt [FFO/Debt] by approximately 150-250 basis points on average, depending to some degree on the size of the company's capital program." He testified that this, of course, is an industry-wide

[61] Moody's Investors Service, Sector Comment, "Tax Reform is Credit Negative for Sector, but Impact Varies by Company," January 24, 2018.

analysis where some issuers will be affected by a greater amount, some by a lesser amount. (Id. at 51)

As stated in Mr. De May's direct testimony, the Company's planned capital expenditures are substantial, amounting to approximately $10.3 billion over the next three years. Mr. De May testified that squeezing the Company's cash flow will have negative impacts upon its credit metrics. (Id.) However, Mr. De May never testified that DEC will receive a credit downgrade.

Upon cross examination by CIGFUR III, witness De May testified that one of the most important credit metrics that the rating agencies use, almost without exception across all agencies and across all companies, is a metric called FFO to debt, which are the funds from operations as a percentage of debt. He testified that DEC's plan for FFO to debt is roughly in the 26 percent range this year. He testified that the floor for DEC's current rating is 25 percent, according to Moody's, and the Public Staff's two year EDIT refund recommendation would take that 26 percent down to 23 percent in year one, to 21 percent in year two, then back to 23 percent in year three, and then to 25 percent thereafter. (T 4 p 436)

Upon cross examination by the Public Staff, DEC witness De May testified that DEC had not during the entire discovery process supplied any of these FFO/Debt calculations to the Public Staff or any of the intervenors; the first day of the expert witness hearing was the first time the Public Staff and intervenors received these numbers. (T 4 p 594) Mr. De May testified that DEC would provide the Public Staff and intervenors copies of his workpapers to see what was and was not included in his calculations. (Id. at 595.)

Witness De May further testified upon cross examination that Public Staff Cross Examination Exhibit Number 11 entitled “Regulated Electric and Gas Utilities” by Moody’s dated June 23, 2017 describes Moody’s credit rating methodology. (Id. at 598.) He testified that Moody’s CFO pre-WC to debt is roughly speaking the same as his FFO to debt. (Id.) He testified that Moody’s gives key financial strength metrics a total of 40%, which includes the CFO pre-WC to debt at 15%. He testified that Moody’s ratings have Aaa at the top, then Aa1, then Aa2, then Aa3. (Id. at 599.)

DEC witness De May testified that Moody’s last rating for DEC’s CFO pre-WC plus interest divided by interest is Aa, for which Moody’s allocates as 10%. He further testified that Moody’s last DEC rating for CFO pre-WC to debt was an A, and the Moody’s zone for an A rating for CFO pre-WC to debt is 22% to 30%, which is different from the 25% as he previously testified. (Id. at 600.)

Witness De May testified that the only financial metric for which DEC does not have an A rating is CFO pre-WC minus dividends to debt, where DEC has a Baa rating. He testified that DEC has an A rating for the last financial metric, debt to capitalization, which has a 7.5% allocation. (Id.)

Mr. De May testified that De May Public Staff Cross Examination Exhibit 12, entitled “Duke Energy Carolinas, LLC Update to Credit Analysis” by Moody’s dated

October 6, 2017, is the most recent Moody's credit report for DEC. He testified that DEC's long term rating is A1 and stable, and the CFO pre-WC to debt on June 30, 2017 is about 25% or 26%. He testified that the DEC three year average of CFO pre-WC to debt was 27.1% with an A rating. (Id. at 601-602.)

Mr. De May further testified that Moody's 12- to 18- month forward view of the four financial credit metrics has none declining, with CFO pre-WC minus dividends to debt upgraded from a Baa to an A. (Id. at 602.) He testified that this Moody's report had DEC's outlook as stable, its issue rating at A1, its First Mortgage Bond rating at Aa2, and its senior unsecured rating at A1. (Id. at 603.) He further that testified all of Duke Energy Corporation's Moody's ratings were either Baa1 or Baa2, considerably below DEC's. (Id. at 603.)

DEC witness De May testified that De May Public Staff Cross Examination Exhibit 14 was DEC's response to Public Staff Data Request 76, Item 4, which stated the Moody's, S&P, and Fitch Credit ratings for the month of February each year, 2013 through 2017, and November 30, 2017, with senior secured, senior unsecured, and outlook for DEC, Duke Energy Corporation, and each electric and gas operating utility subsidiary of Duke Energy Corporation. He testified that Moody's November 30, 2017, senior secured rating for DEC was Aa2 and the senior unsecured was A1 (T 5 pp 22-23)

Mr. De May testified DEC has a Moody's senior secured rating of Aa2 all the way back to February 2013, which is when DEC was upgraded from A1. He testified DEC has a Moody's senior unsecured rating of A1 all the way back to

February 2014. (Id. at 23.) He testified that DEC's A1 senior unsecured rating is higher than the senior unsecured rating of any of Duke Energy Corporation's electric and gas operating utility subsidiaries on November 30, 2017, and also each February 2014 through February 2017, except Duke Energy Progress, which also had a senior unsecured A1 rating February 2014 and 2015. Mr. De May testified that it is an emphatic yes that DEC has the strongest credit ratings in the Duke complex. (Id. at 24.)

Witness De May testified that at Duke Energy Corporation's request, Fitch in 2017 stopped rating all the operating Duke companies. (Id. at 24 He testified that the Fitch senior secured rating for DEC on February 16, 2017, was AA-, which was also the February 2016 rating. He testified that the DEC Fitch senior secured ratings and DEC's senior unsecured rating of A+ for these two years were stronger than any other Duke Energy Corporation companies. (Id. at 25.)

DEC witness De May further testified upon cross examination that De May Public Staff Cross Examination Exhibit 15, is a January 24, 2018, Moody's Report entitled "Regulated Utilities – US Tax reform is credit negative for sector, but impact varies by company." He agreed that Moody's stated on page one of this report:

> Utilities with weaker than expected financials are most affected. The potential for lower cash flows hurts the credit profile of numerous regulated utilities that already have weakening financial projections. Major holding companies affected include American Electric Power, Consolidated Edison, Dominion Energy, Duke Energy Corporation, Entergy Corporation, and the Southern Company.
>
> (Id. at 28.)

He read further from page one of this Moody's report which stated:

> Most utilities are still well positioned within their credit profiles. The vast majority of utilities and their holding companies are well positioned within their credit profiles thanks to supportive regulatory relationships and a capital structure balanced between both debt and equity.
>
> (Id. at 29.)

Witness De May testified that in this Moody's January 24, 2018 report, DEC is not mentioned, but Duke Energy Corporation was changed from a stable outlook to negative outlook and is listed as one of the utilities with weakened, or weakening financial profiles due to tax reform. (Id. at 29.) He testified that Moody's listed Duke Energy Corporation's three year average CFO pre-WC to debt at 14.7%, and for 2018 – 2019 at 13 – 15%. (Id. at 30.) He testified that DEC was not listed among the vertically integrated operating utilities with weakened or weakening financial profiles due to tax reform. (Id. at 30.)

Witness De May testified that De May Public Staff Cross Examination Exhibit 16 was De May Rebuttal Testimony Exhibit 3, a listing of the Moody's senior unsecured credit ratings for DEC and 35 other operating electric utilities. He testified that DEC was one of only six companies with a Moody's A1 rating, and the remaining 30 companies had Moody's ratings below A1, thereby placing DEC approximately in the top 15%. (Id. at 32.)

Mr. De May testified that De May Public Staff Cross Examination Exhibit 17 is DEC's response to Public Staff Data Request 146, Item 8, showing the senior secured credit ratings for DEC and the same 36 electric operating companies. He testified that 22 of these companies did not have senior secured ratings, as these companies do not issue senior secured debt. (Id. at 34.) He testified that of the 14 companies with senior secured debt ratings, DEC was one of only four with a Moody's Aa2 rating and the other ten companies had lower ratings.

Upon further cross examination, Mr. De May testified that DEC recently issued two first mortgage bonds with effective settlement dates of March 1, 2018, each Moody's rated Aa2 - a five year $500 million bond with coupon rate of 3.05%, and a 30 year $500 million bond with coupon rate of 3.95%. (Id. at 34.) He testified that the prospectus supplement for these bonds only credit chart was the SEC required ratio of earnings to fixed charges at 4.8%, which is DEC's highest ratio since 2012. (Id. at 35.)

De May Public Staff Cross Examination Exhibit 17 includes a listing by Merchant Bond Record of interest rates for Moody's Utility Bonds rated Aa and A for each year 1975 through 2016, and each month of 2017. Mr. De May testified that the five year 2012 through 2016 average differential between the Aa and A was .19%, for the twelve months of 2017 was .18%, and the 25 years 1992 through 2017 was .17%. (Id. at 37.)

Mr. De May testified that DeMay Public Staff Cross Examination Exhibit 20 was a listing of DEC long term debt as of December 31, 2017. Line 16 listed a 30 year, $550 million, with coupon rate of 3.70%, First Mortgage Bond Taxable with issue date November 14, 2017, which Mr. DeMay testified was issued with a Moody's rating of Aa2. He testified that this was the lowest coupon rate for a DEC 30-year bond for a substantial period of time, if not ever. (Id. at 39-40.) Mr. De May testified that of DEC's December 31, 2017 long term debt, the secured debt was 83.7% of the total long term debt. (Id. at 43.)

DeMay Public Staff Cross Examination Exhibit 21 was the February 20, 2018, Duke Energy Corporation Fourth Quarter Earnings Review and Business Update, with presenters Lynn Good, Chairman, President and CEO, and Steve Young, Executive VP and CFO. Mr. De May testified that the slide on page 4 listed the Duke Energy Corporation February 16, 2018 dividend yield at 4.6%. (Id. at 45.) Mr. De May denied that Duke Energy Corporation's dividend yield was approximately 100 basis points higher than the average for electric utilities, stating the Duke Energy Corporation's dividend yield was not out of line with companies like Duke Energy Corporation. (Id. at 46.)

These dividend yield statements by DEC witness De May were later materially contradicted by AGO witness Dr. Woolridge's Supplemental Exhibit JRW-2, page 2 of 6 of his updated DCF study showing the 30 day, 90 day, and 180 day dividend yields of Duke Energy Corporation and Dr. Woolridge's and Mr. Hevert's proxy groups. Dr. Woolridge testified that Duke Energy Corporation's 30 day annualized dividend yield was 4.64% and the average 30 day annualized dividend yield for Dr. Woolridge's and Mr. Hevert's proxy groups was 3.6% and the median was 3.4%, whereby Duke Energy Corporation's 30 day annualized dividend yield was 104 basis points over the average and 124 basis points above the median. (T 11 p 216-17)

Mr. De May testified that Slide 41 of De May Public Staff Cross Examination Exhibit 21 stated DEC would issue $2.0 billion of debt in 2018 and that DEC had already issued $1.0 billion of debt. (Id. at 52.) He testified Slide 42, which is entitled Liquidity summary (as of December 31, 2017), lists a Master Credit Facility to which DEC has available capacity of $725 million. (Id. at 52-54.) He testified that Slide 43 lists the long term debt maturities for DEC with $1.2 billion in 2018, only $5 million in 2019, and $905 million in 2020. (T 5 p 55)

Mr. De May further testified that slide 44 lists the Duke companies' Moody's and S&P debt ratings for which DEC debt ratings are as high or higher as any of the Duke Companies. (Id. at 55.) He testified that Slide 45 listing FFO/Debt with the tax rate reduced to 22% in 2018 has DEC's 2018 estimated FFO/Debt at 26% (Id. at 56) Mr. De May further testified that DEC has a very strong balance sheet and he wished every utility in Duke Energy Corporation's portfolio had the credit strength of DEC. (Id. at 82-83.)

On redirect, Mr. De May testified that the October 6, 2017 Moody's Credit Opinion for DEC listed factors that could lead to a downgrade, including a decline in cash flow metrics if FFO to debt fell below 25% on a sustained basis. (Id. at 85.)

He testified that if the Public Staff's proposal is implemented, DEC's FFO to debt ratio would be falling below the 20-25% level, certainly in the first couple of years, until some kind of bounce back occurred in the later years. (at 86.)

Public Staff witness Parcell testified as shown on Exhibit DCP-1, Schedule 3, that DEC's senior debt has been rated in the "Aa" category by Moody's since 2013, and DEC's ratings by S&P has been "A" over that period. He testified that DEC's ratings have been higher than those of Duke Energy Corporation throughout this period. He further testified that the current senior secured debt ratings of DEC and other Duke Energy Corporation utility subsidiaries as shown on DEC's response to Public Staff Data Request 76, Item 4 are as follows:

Company	Moody's	S&P
DEC	Aa2	A
DE Progress	Aa3	A
DE Florida	A1	A
DE Ohio	A2	A
DE Indiana	Aa3	A
DE Kentucky	Baa1	A-

He testified that DEC has the highest ratings among the Duke Energy Corporation subsidiaries. He further testified the higher ratings of DEC are indicative of relatively lower risk. (T 26 p 822)

AGO witness Woolridge testified that he uses credit ratings to assess the riskiness of DEC relative to his and Mr. Hevert's proxy groups. Credit rating agencies consider the business and financial risk of utilities in the rating process. DEC's S&P's issuer credit rating of "A-" is one notch above the average of his and

Mr. Hevert's two proxy groups ("BBB+") and DEC's Moody's issuer credit rating of "A1" is three notches above the average of the two proxy groups ("Baa1"). He testified that contrary to Mr. Hevert's assertions, DEC is less risky than the proxy groups. (T 11 p 107)

Tech Customers witness Strunk, in his direct testimony, stated that he prepared two exhibits on bond ratings. Exhibit KGS-5 presents a comparison of DEC's Moody's Issuer Rating to those of the proxy group companies. His company, National Economic Research Associates, compiled a list of all of the operating subsidiaries of the companies in witness Hevert's proxy group and restricted the analysis to those subsidiaries that currently have a Moody's Issuer Rating in place. He testified, as illustrated in Exhibit KGS-5, that DEC's Moody's Issuer Rating of "A1" is on the highest end of the spectrum, with 93% of the operating companies having a lower rating than DEC, indicating low risk compared to the proxy group operating companies. (T 26 p 502)

Tech Customers witness Strunk further testified that Exhibit KGS-6 compares DEC's Fitch Long-Term Issuer Default Rating to those of the Hevert proxy group companies. He compiled a list of all of the operating subsidiaries of the companies in the proxy group and restricted the analysis to those subsidiaries that currently have a Fitch Long-Term Issuer Default Rating in place. He testified that DEC's Fitch Long-Term Issue Default Rating of "A" is on the highest end of the spectrum with 83% of the operating companies with ratings lower than DEC, indicating low risk compared to the proxy group operating companies. For this comparison, he used DEC's 2015 Fitch Long-Term Issuer Default Rating, because Fitch has since withdrawn its ratings of DEC. He testified that he did not see any evidence to suggest that this would not be the prevailing rating today. (Id. at 503-04.)

Tech Customers presented the supplemental testimony of Dr. Sharon Brown-Hruska and Mr. Strunk. They testified that based on the projected FFO/Debt ratios proffered by Mr. De May and a review of the most recent DEC credit assessment from S&P, they found that the projected FFO/Debt ratios, adjusted so as to eliminate the request for an additional $200 million in revenue requirement for cash flow, will not jeopardize DEC's credit metrics. They testified that DEC's projections demonstrate that DEC is on track to maintain and even exceed – *after implementation of the Tax Act* – FFO/Debt ratios in the range of 24 to 26 percent, which is the base case assumption relied upon by S&P *before the Tax Act became law.* Consequently, they recommended that the Commission reject DEC's request for a $200 million annual increase in its revenue requirement. (Id. at 514.)

Dr. Brown-Hruska and Mr. Strunk testified that S&P does not express any concern regarding FFO/Debt ratios for DEC that fall within a range of 24 to 26 percent. They testified S&P characterizes DEC's credit metrics as follows:

> Our assessment of DEC's financial risk profile reflects our base-case assumptions under which we project the company's FFO to debt will remain in the 24%-26% range benefiting from planned base rate increases and modest load growth. At the same time, we project that debt leverage will remain consistent with the rating

> category with debt to EBITDA that ranges from 2.8x-3x, in large part reflecting the company's robust and regulatory approved capital structure.[62]

They testified that nowhere in its report does S&P suggest that an FFO/Debt ratio falling in the range of 24 to 26 percent will jeopardize DEC's credit rating. (Id. at 514.)

Tech Customers witnesses Brown-Hruska and Strunk further testified that Moody's does not express any concern regarding FFO/Debt ratios consistent with DEC's after-the-Tax-Act projections, adjusted so as to eliminate the request for an additional $200 million in cash flow. They testified that Moody's characterized DEC's credit metrics as follows:

> Factors that Could Lead to a Downgrade[:] if the ratio of CFO pre-W/C to debt [i.e., FFO/Debt] fell below 25% on a sustained basis.[63]

(Id. at 514-15.)

Witnesses Brown-Hruska and Strunk prepared a chart that depicts the FFO/Debt ratio over time with and without the $200 million in enhanced revenue requirement and cash flow. They testified that their Confidential Figure 1 uses the projected FFO/Debt ratios provided by Mr. De May, then eliminates $200 million in cash flow to establish where the ratio should be expected to fall if the Commission

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[62] Standard & Poor's Global Ratings, Ratings Direct, "Duke Energy Carolinas LLC", (July 24, 2017), p. 4.

[63] Moody's Investors Service, "Credit Opinion Duke Energy Carolinas, LLC", October 6, 2017, p. 2 (emphasis added).

elects to deny DEC's request for $200 million per year in accelerated cost recovery. They testified that as shown, the FFO/Debt ratio does not fall below the range anticipated by S&P, even without the requested $200 million in additional cash flow. (Id. at 515.) They further testified that Figure 1 illustrates that DEC's credit metrics satisfy the 25% target identified by Moody's in the Credit Opinion cited by Mr. De May.[64] They testified that while Figure 1 indicates that DEC's FFO/Debt ratio will dip, the ratio does not fall below 25% on a "sustained basis" as noted in the Moody's report. (Id. at 516.)

Dr. Brown-Hruska and Mr. Strunk further testified that S&P's most recent report does not specify a FFO/Debt rating threshold for a DEC downgrade. Rather, S&P ties the DEC rating to the parent company rating and explains that it would implement a downgrade under the following circumstances:

> S&P could lower credit ratings for Duke Energy Corporation "by one notch" if it's [*sic*] "financial performance weakens such that FFO to debt is consistently below 15% as a result of its inability to recover invested capital, including coal ash remediation costs, in a timely manner".[65]

Moody's suggests that a fall in FFO/Debt below 25% "on a sustained basis" could lead to a downgrade. They testified that the use of the terms "consistently"

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[64] *See* Moody's Investors Service, Credit Opinion dated October 6, 2017, Duke Energy Carolinas, LLC (DEC De May Rebuttal Exhibit 7), at 2 (noting as a factor that could lead to a downgrade "[a] decline in cash flow metrics, for example, if the ratio of CFO pre-W/C to debt fell below 25% on a sustained basis").

[65] Direct testimony of Stephen G. De May for Duke Energy Carolinas, LLC, Docket No. E-7, Sub 1146 at p. 12. (emphasis added)

and “on a sustained basis” by the credit rating agencies is inconsistent with a downgrade given DEC’s projected FFO/Debt ratios. (Id. at 517.)

Dr. Brown – Hruska and Mr. Strunk testified that in their Figure 3 they did a comparison of DEC with operating company subsidiaries of proxy group holding companies that have the same credit rating from S&P. They testified that this exhibit demonstrates that DEC’s FFO/Debt ratios are healthy, and among the healthiest among the proxy group operating companies, both on a current and projected basis. They testified that credit metrics do not justify the request for $200 million per year in additional revenue requirement and DEC’s request should be rejected. (Id. at 518.)

Public Staff Director of the Economic Research Division, John Hinton, testified in his second supplemental testimony that DEC provided the Public Staff with the projected credit metrics of funds from operations over debt (FFO/Debt) under two future scenarios: a scenario with the Public Staff’s Tax Refund Proposal for unprotected Federal EDIT refund over a two-year period and a scenario with the Company’s Federal EDIT Refund Proposal over twenty years with the FFO/Debt, both projected over the five-year period 2018-2022. (T 22 p 265)

Public Staff witness Hinton testified that DEC, at the request of the Public Staff, also prepared FFO/Debt over an alternative five-year Federal EDIT refund period and his testimony is based on this five-year Federal EDIT refund period.

Witness Hinton testified that the Public Staff was not provided with detailed support for the projected cash flow and debt data incorporated in the five-year Federal EDIT refund period FFO/Debt calculations. He testified that he and another Public Staff employee were allowed to view limited support for the calculation of the FFO/Debt ratio; however, the information contained none of the underlying assumptions for the funds flow from operations and limited information on debt projections. He testified that the Public Staff does not know if the Company's FFO numbers are reasonable or skewed to the low side, thereby reducing the FFO/Debt percentages, as the Company refused to provide the Public Staff with the inputs the Company used. (Id. at 266.)

Mr. Hinton testified that he used the unverified Company data combined with CFO Pre-WC/Debt data from the Moody's DEC October 6, 2017 credit report to calculate a three-year average, which indicated that DEC's FFO/Debt ratio will remain above the 25% level for 2018, then the ratio is expected to slightly decrease to a level above 24% for 2019 through 2021 and return to 25% in 2022. Mr. Hinton testified that given that Mr. De May stressed the importance of FFO/Debt, the Public Staff applied this funds flow metrics in place of the Cash Flow from Operations (CFO) metric[66] that Moody's Investor Services often cites. (Id.at 266-67.)

[66] In regard to Moody's rating methodology, the difference between cash flow from operations and funds flow from operations is the inclusion of other regulatory assets and liabilities shown on the Company's cash flow statement with its SEC filings. Public Staff witness Hinton

Public Staff witness Hinton testified that a temporary decrease in FFO/Debt will not likely lead to a downgrade of the Company's "Aa2" rating on its first mortgage bonds or its "A1" senior unsecured bonds. He testified that Moody's, like S&P, focuses on net income and cash flow metrics from ongoing and continued operations over time. As such, Moody's averages its financial metrics over three years. He testified that Exhibit JRH-3 contains Moody's DEC October 6, 2017 report entitled "Update to Credit Analysis" where it notes factors that could lead to a downgrade, such as a **sustained** (emphasis added) decline in cash flow metrics below 25%. Moody's, in its Regulated Electric and Gas Utilities Ratings Methodology dated June 23, 2017, on page 20 stated:

> Multi-year periods are usually more representative of credit quality because utilities can experience swings in cash flows from one-time events, including such items as rate refunds, storm cost deferrals that create a regulatory asset, or securitization proceeds that reduce a regulatory asset. Nonetheless, we also look at trends in metrics for individual periods, which may influence our view of future performance and ratings.

(Id. at 267.)

Mr. Hinton further testified that according to Moody's Rating Methodology and DEC's low business risk profile, the CFO/Debt metric would need to fall below 19% before DEC's senior unsecured debt would qualify for a downgrade from its "A1" rating, as shown in Exhibit JRH-4. (Id. at 268.)

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testified that the impact of the regulatory assets and liabilities will tend to offset each other and not materially change the conclusion he reached. (T 22 p 267)

Public Staff witness Hinton also testified as to his opinion if DEC's first mortgage bonds were downgraded from "Aa2" to "Aa3" and his estimate of the added cost of debt capital. He testified that based on data by Moody's Corporate Bond Yields as reported by Mergent Bond Record, the spread between "Aa" rated utility bonds and "A" rated utility bonds is 17 basis points. He testified that the increase in yield associated with a downgrade to "Aa3" would likely be considerably less. He testified that in light of the Company's financial forecasts, it is his opinion that the added cost of debt capital from a downgrade to an "Aa3" rating would not be unreasonably burdensome on the Company nor will it affect ratepayers. He also testified that it does not appear that any DEC downgrade resulted from the 1986 change in the federal income tax rate. (Id. at 270.)

Public Staff witness Hinton concluded his second supplemental testimony by stating that based on his review of the credit metrics provided by Company witness De May, and Moody's Investor Service reports, that he believes it is unlikely that spreading the Federal EDIT refund over five years will result in a debt rating downgrade, and the five year refund is reasonable and fair to the DEC's ratepayers and the Company. (Id. at 271.)

On cross examination by DEC, witness Hinton testified that Exhibit JRH-2 attached to his second supplemental testimony contained DEC provided FFO/Debt information assuming the EDIT is refunded over a five-year period. He testified that he took the Moody's DEC October 6, 2017 report actual FFO/Debt over the last several years and combined the Moody's DEC historical information with the five-years refund information DEC provided to the Public Staff data response. He testified that when Moody's does its quantitative analyses, Moody's relies on three-year moving averages. He testified that Moody's does not look at one year in particular in isolation. He testified that Moody's looks at a year and the last two prior years. (T 22 p 294)

Mr. Hinton testified that he combined the Moody's DEC FFO/Debt actuals, with the five year refund DEC FFO/Debt information resulting in a three-year average, and the results were FFO/Debt 26% for 2018, then 24% for 2019 through 2021, and returned to 25% in 2022, which is shown on DEC Hinton Cross Examination Exhibit 1.[67] (Id. at 296.)

Mr. Hinton testified that on page 6 of Moody's DEC October 6, 2017 report Exhibit JRH-3 under "Rating Methodology and Scorecard Factors", Factor 4 CFO to debt has three-year historical averages. (Id. at 298-99.) He testified that to the right of that is a column "Moody's 12 to 18 Month Forward View". Mr. Hinton testified that he believes Moody's looks at both the three-year historical average and the 12 to 18 month forward view. (Id. at 300.)

Mr. Hinton testified that the FFO/Debt is only one of the factors Moody's considers. He testified that Moody's assigns regulatory framework 50%, and diversification of assets 10%. The Moody's rating methodology assigns financial

[67] DEC's counsel advised the Commission that the DEC provided five year EDIT refund FFO/Debt information is not confidential as stated in Mr. Hinton's second supplemental testimony. (Id. at 295.)

strength the remaining 40%, which includes the CFO pre-WC to debt 15%. Mr. Hinton testified that he believes it is unlikely that Moody's will downgrade DEC for a three-year temporary decline in FFO/Debt. (Id. at 301.)

On redirect, Mr. Hinton testified that when he went to DEC's office in Raleigh, he was given only two pieces of paper that each showed only one FFO number for each of the five years, the total debt number for each of the five years, and the resulting FFO/Debt percentage for each of the five years. (Id. at 311.) Mr. Hinton testified that he used the DEC numbers for 2018 through 2022. He testified that he did not have any idea what was in DEC's FFO numbers. (Id. at 312.) He testified that the Public Staff did ask whether the DEC coal ash remediation costs through November 2017, was or was not in DEC's numbers, and DEC did not provide an answer. (Id. at 313.) He further testified that the Public Staff asked whether the run rate on coal ash remediation ongoing environmental costs were or were not in the DEC FFO numbers, and, if included, what was included, and DEC provided no information. (Id. at 314.) He testified that the Public Staff asked DEC what was in the FFO numbers for nuclear decommissioning, and DEC provided no information. (Id.)

Mr. Hinton further testified that DEC did not provide any information for the FFO as to any future rate cases that would affect the numbers. (Id.) He testified that he has no idea whether DEC put into the FFO numbers the $6.7 million executive or incentive payments reduction in operating expenses agreed to in the Stipulation. He testified that he has no idea whether DEC put into the FFO numbers the $2.4 million Stipulation number reducing the Board of Directors operating expenses. (Id. at 315.) He testified that no information was provided on customer growth rates or increase in electric sales rates, whether industrial, commercial, or residential. (Id.) He also testified that DEC never told the Public Staff whether DEC's FFO numbers included DEC's requested $200 million. (Id. at 316.) He also testified that the Public Staff asked in its data request what ROE DEC used for its FFO calculations and DEC refused to provide that information. (Id. at 318.)

Mr. Hinton testified that nowhere in the Moody's reports does Moody's define "sustained basis". (Id. at 316.) He testified that in all the Moody's reports he has seen in recent years, Moody's always uses a three-year average for financial metrics. (Id. at 316-317.) He testified that the Tax Act was enacted before DEC executed the Stipulation agreeing to the 9.9% ROE and 52% equity capital structure. (Id. at 318.)

The Commission concludes as stated elsewhere in this Order that the Commission's duty under G.S. 62-133 is to set rates as low as reasonably possible without impairing the Company's ability to raise capital needed to provide reliable electric service and recover its cost of providing service. GS 62-133 (b)(4) states that in fixing the rates for any public utility, the Commission shall:

> Fix such rate of return on the cost of the property ascertained pursuant to subdivision (1) of this subsection as will enable the public utility by sound management to produce a fair return for its shareholders, considering changing economic conditions and other factors, including, but not limited to, the inclusion of construction work

> in progress in the utility's property under sub-subdivision b. of subdivision (1) of this subsection, as they then exist, to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and to compete in the market for capital funds on terms that are reasonable and that are fair to its customers and to its existing investors.

The Commission has determined that the approved return on equity and DEC capital structure will enable DEC by sound management to compete in the market for capital funds on terms that are reasonable and fair to DEC's customers and DEC's existing investors. Nowhere in the Public Utilities Act, including G.S. 62-133, does it state the Commission is responsible for DEC's credit metrics. It is the responsibility of DEC through sound management to manage and protect its credit metrics.

DEC witness De May opined that squeezing the Company's cash flow will have negative impacts on DEC's credit metrics. Mr. De May never testified DEC will receive a credit downgrade nor did DEC present credible evidence that either Moody's or S&P would downgrade DEC's credit rating if the Commission did not adopt DEC's requested Federal EDIT refund treatment or the unspecified $200 million additional annual revenue requirement.

The overwhelming uncontroverted evidence was that DEC has extremely strong credit ratings as testified to by DEC witness De May, Public Staff witnesses Parcell and Hinton, AGO witness Woolridge, and Tech Customers witnesses Brown-Hruska and Strunk. The uncontroverted evidence was that DEC's current Moody's credit ratings are senior secured Aa2, senior unsecured A1, with Stable outlook. The Aa2 senior secured is higher than all of the Duke Energy Corporation's electric utility operating subsidiaries. This DEC senior secured Aa2 is also one of four electric utility operating companies with a senior secured Aa2 rating on De May Public Staff Cross Examination Exhibit 16, a group of comparison companies selected by Mr. De May, with the remaining ten electric operating companies rated below Aa2.

DEC's senior unsecured Moody's rating of A1 is also higher than all of the Duke Energy Corporation's electric utility operating subsidiaries. This Moody's DEC senior unsecured A1 rating is also one of only six electric utility operating companies with an A1 senior unsecured A1 rating on De May Public Staff Cross Examination Exhibit 17, again a group of comparison companies selected by Mr. De May, with the remaining 30 electric operating companies rated below A1.

The Commission concludes that DEC's FFO/Debt is unlikely to fall below 25% for a sustained period of time if the Commission accepts the Public Staff's proposal to flow back Federal EDIT to customers over five years and deny the Company's $200 million accelerated depreciation request. The Public Staff's proposal to flow back unprotected Federal EDIT over five years instead of the originally proposed two year periods mitigates the concerns expressed by witness De May in his rebuttal testimony and at the evidentiary hearing. DEC failed to recall Witness De May for the purposes of evaluating the Public Staff's five year Federal EDIT proposal on DEC's credit metrics, thus leaving the Public Staff's evidence (which consisted of calculations undertaken by DEC) uncontroverted.

Based on the findings presented by the Public Staff following its analysis of DEC's FFO/Debt calculations during a five year unprotected Federal EDIT flowback, the Commission determines that DEC's FFO/Debt ratio would only fall below 25% for a temporary three year period, at the very most.[68]

As shown in Tech Customers witness Strunk's direct testimony Exhibit KGS-5, which compares DEC to all the operating subsidiaries in DEC witness Hevert's proxy group, DEC's Issuer Rating is A1, which is on the highest end of the spectrum, with 93% of the operating companies having a lower rating than DEC. Mr. Strunk's direct testimony Exhibit KGS-6 compared DEC's Fitch Long-Term Issuer Default Rating to the same operating companies subsidiaries of Mr. Hevert's proxy group, with DEC's A rating being on the highest end of the spectrum with 83% of these operating companies with lower ratings than DEC. The supplemental testimony of Tech Customers witnesses Brown-Hruska and Strunk stated that nowhere in the S&P DEC report they reviewed does S&P suggest that an FFO/Debt ratio falling in the range of 24 to 26 will jeopardize DEC's credit rating.

Although DEC introduced into evidence the statement in the Moody's October 6, 2017 Report that if DEC's ratio of CFO pre-W/C to debt fell below 25% on a **sustained** basis, it could lead to a credit downgrade, DEC never presented

[68] The Commission notes that DEC introduced its tax proposal extremely late in the proceeding despite the fact that the tax reduction legislation was enacted well before the hearing. Public Staff witness Hinton detailed the lack of information provided by DEC to allow a comprehensive evaluation of the cash flow impacts arising from the Public Staff's revised tax refund proposal. The Commission does not believe it is appropriate to allow DEC to benefit from its failure to provide timely and complete information that would allow a full vetting of the impact of the various tax refund proposals.

credible evidence as to what Moody's considers a sustained basis, and Moody's only stated it "could" lead to a downgrade rather than it "would" lead to a downgrade. Various parties including the Public Staff, AGO, and Tech Customers presented evidence to rebut DEC's contention, which tended to show that DEC would not experience a credit downgrade under these circumstances. The Commission notes that credit ratings are, in large part, an assessment of a company's ability to make debt payments and meet other financial obligations. There is nothing in the record indicating that implementation of the Public Staff's five year Federal EDIT refund plan would threaten DEC's ability to make debt payments or to meet other financial obligations. Based on the totality of the evidence in the record, the Commission concludes that DEC has a very strong balance sheet that is capable of withstanding a three year temporary decline in FFO/Debt without a corresponding decrease in credit ratings. . Furthermore, a temporary three year period is not a "sustained period" that would necessarily precipitate a decrease in DEC's credit rating.

The Commission concludes that DEC has not provided probative and credible evidence that by the Commission approving the Public Staff's recommended Federal EDIT five year refund period and denying DEC's request for an increased $200 million revenue requirement to compensate for the Tax Act, DEC would lack the ability by sound management to compete in the market for capital funds on terms that are reasonable and fair to DEC's customers and DEC's investors.

Even if the rating agencies unexpectedly lowered DEC's credit rating during a temporary period following a drop in the FFO/Debt ratio, the Commission finds there is no evidence in the record that, on balance, customers would be harmed. A temporary decrease in a credit rating only impacts customers to the extent DEC issues debt during that period of time, and that impact is only realized by customers once DEC seeks to include such costs in its cost of capital calculations in a general rate case. As DEC is the most highly rated of Duke Energy Corporation's subsidiaries, a reduction in one credit grade would not present a material negative impact to customers, especially when balanced against the significant customer benefit from flowing back unprotected Federal EDIT over five years instead of twenty years.

Finally, the Commission concludes that Duke Energy Corporation has numerous tools to mitigate any negative FFO/Debt impacts. First, Duke Energy Corporation can issue additional equity to address any cash flow deficiencies. While this may not be preferable to the Company because it could negatively impact earnings per share, this is not a concern of the Commission. The Commission expects DEC to manage its finances in a manner to protect its credit rating for the benefit of customers. Second, as discussed elsewhere in the Order, DEC has proposed significant capital expenditures through the Power Forward initiative. If DEC encounters materially negative FFO/Debt impacts, DEC can simply delay implementation of Power Forward components until cash flow issues have been resolved. DEC witnesses admitted during the hearing that Power Forward could be delayed or implemented over a longer period of time, thus reducing the capital expenditures in any given year. This would be an appropriate step to managing constrained cash flows arising out of Federal EDIT flowbacks.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 88

The evidence supporting this finding of fact and conclusion is contained in the testimony of DEC witness McManeus.

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, it 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. 89-92

The evidence supporting these findings and conclusions is contained in the Stipulation, DEC'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 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 (Coal Ash, Storm Costs) reflecting the Public Staff's position on the unresolved issues. The resulting proposed revenue requirement 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. 93

The evidence supporting this finding of fact and conclusions is contained in the Application, the testimony and exhibits of all the witnesses, the Stipulation, and the entire record in this proceeding.

Pursuant to G.S. 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 G.S. 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 G.S. 62-30, et seq.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation filed by DEC and the Public Staff and the settlement agreement (as amended) entered into by DEC, NCLM, and the Cities of Concord, Kings Mountain, and Durham are approved in their entirety.

2. That DEC shall be allowed to increase its rates and charges effective for service rendered as to ___, 2018, so as to produce a decrease in gross annual revenue for its North Carolina retail operations of $385,697,000 for the first four years that rates approved herein are in effect, a decrease of $325,595,000 for the fifth year that rates approved herein are in effect, and a decrease of $101,230,00 thereafter, based upon the adjusted test year level of operations, as set forth in Boswell Third Supplemental and Stipulation Exhibit 1 Corrected.

3. That the approved base fuel and fuel-related cost factors are as follows (amounts are cents per kWh, excluding regulatory fee): 1.7828 for residential customers; 1.9163 for general service and lighting customers; and 2.0207 for industrial customers.

4. That the Company shall implement an increment rider, effective ______ 1, 2018, and expiring at 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 (priced at $73.23 per ton). The interest on any under- or over-collection shall be set at the Company's net-of-tax overall rate of return. The Company shall

adjust the rider annually, concurrently with its DSM/EE, REPS, and Fuel Adjustment riders.

5. That the Company shall conduct an analysis in consultation with the Public Staff demonstrating the appropriate coal inventory level given market and generation changes since the Company's rate case in Docket No. E-7, Sub 1026. The analysis shall be completed by March 31, 2019.

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

7. That the appropriate revenue requirement for the first five years should be reduced by the Federal EDIT Rider decrement of $224.365 million.

8. That the aspects of rate design agreed upon in the Stipulation are approved and shall be implemented.

9. That the JRR and JRR Rider are approved as provided in the Stipulation, but modified as recommended by the Public Staff.

10. That the Basic Facilities Charge shall be adjusted in accordance with the recommendation of Public Staff witness Floyd.

11. That the Company's request for a Grid Rider is denied. DEC shall include in its smart grid technology plan filings, required by Commission Rule R8-60.1, the following detailed information regarding Power Forward projects: (1) the purpose of each project or categories 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 transmission and distribution assets affected by the project. The Company shall consult with the Public Staff regarding what information should be included and in what level of detail.

12. That the Company shall file annual cost of service studies based on both the SCP and SWPA methodologies.

13. That DEC shall be, and is hereby, authorized to establish a regulatory asset to defer and amortize the costs of its Customer Connect Program (CCP). The regulatory asset account shall accrue AFUDC until the DEC Core Meter-to-Cash release (Releases 5-8) of the CCP goes into service of January 1, 2023, whichever is sooner, at which time a 15-year amortization shall begin.

14. That DEC shall remove the costs incurred for the architectural and engineering design of a visitors' center at the Lee Nuclear Project.

15. That no further AFUDC on the Lee Nuclear Project shall be allowed after December 31, 2017.

16. That DEC shall recover the costs of the Lee Nuclear Project, except as addressed in Findings of Fact 36 and 37 above, through amortization over a period of 12 years, with no return on the amortized balance.

17. That the Company's annual revenue requirement shall be reduced by $29.1 million (exclusive of tax effects) to advance the return to ratepayers of the NDTF overfunding. In conjunction with this reduction in the annual revenue requirement, the Company shall establish a regulatory asset for the difference between the credit nuclear decommissioning expense recommended by Public Staff witness Hinton and the zero amount of nuclear decommissioning expense proposed by the Company, adjusted appropriately for income tax effects.

18. That DEC shall use the Public Staff's proposed depreciation rates as shown on Public Staff witness McCullar's Exhibit RMM-1.

19. That the Commission's approval in this Order of 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 those costs in any future regulatory proceeding.

20. 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.

21. 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 a schedule illustrating the rates of return by class based on the revenues produced by the rates for each schedule; and

22. 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 increase by mailing the notice to each of its North Carolina retail customers during the billing cycle following the effective date of the new rates.

This ____ day of _____________, 2018.

NORTH CAROLINA UTILITIES COMMISSION

M. Lynn Jarvis, Chief Clerk