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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

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

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

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

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

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

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

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

APPEARANCES:

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For the Carolina Industrial Group for Fair Utility Rates III (CIGFUR III), Piedmont Electric Membership Corporation (Piedmont EMC), Rutherford Electric Membership Corporation (Rutherford EMC), Haywood Electric Membership Corporation (Haywood EMC), and Blue Ridge Electric Membership Corporation (Blue Ridge EMC):

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For North Carolina Waste Awareness and Reduction Network (NC WARN):

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For North Carolina Sustainable Energy Association (NCSEA):

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For the City of Durham (Durham):

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Environmental Defense Fund
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For The Kroger Co. (Kroger):

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Kurt J. Boehm
Jody Kyler Cohn
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For the Sierra Club:

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Matthew D. Quinn
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Dorothy E. Jaffe
Bridget M. Lee
Sierra Club
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For Appalachian State University (ASU):

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Christopher S. Dwight
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Barbara L. Krause, Deputy General Counsel Appalachian State University B.B. Dougherty Administration Building, Third Floor 438 Academy Street, P.O. Box 32126, Boone, North Carolina 28608

For Rate Paying Neighbors of Duke Energy Carolinas, LLC's Coal Ash Sites (Rate-Paying Neighbors):

Mona Lisa Wallace
John Hughes
Marlowe Rary
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For North Carolina Farm Bureau Federation, Inc. (NCFB):

H. Julian Philpott, Jr., Secretary and General Counsel
North Carolina Farm Bureau Federation, Inc.
Post Office Box 27766, Raleigh, North Carolina 27611

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

Gudrun Thompson, Senior Attorney
David Neal, Senior Attorney
Southern Environmental Law Center
601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For North Carolina League of Municipalities (NCLM):

Karen M. Kemerait
Deborah K. Ross
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For Apple Inc., Facebook Inc., and Google Inc. (collectively, the Tech Customers):

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Charlotte: Brian Kasher, Mary Anne Hitt, Yvette Baker, Melvina Williams, Lilly Taylor, Steve English, Nancy Nicholson, Sally Kneidel,

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Callina Satterfield, Amy Brown, Roger Hollis, Kent Crawford, Ritchie Johnson, Ernie McLaney, Willie Dawson, Pat Moore, Beth Henry, James Sprouse, Charles Talley, June Blotnick, Charles King, Meg Houlihan, Steve Copulsky, Elaine Jones, Christian Cano, Joel Segal, Kathy Sparrow, Rick Lauer, Nicholas Rose, Wells Eddleman, Walker Spruill, Violet Mitchell, and Holliday Adams

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

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

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

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

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

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

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

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

FINDINGS OF FACT

Jurisdiction

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

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

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

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

The Application

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

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

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The Stipulation

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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Adjustments to Cost of Service

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

State EDIT

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

Customer Connect

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

Lee Combined Cycle

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

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

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

Requested Coal Combustion Residuals (CCR) Fuel Costs

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

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

Base Fuel Factor

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

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

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

Coal Inventory

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

Cost of Service Allocation Methodology

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

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

Lead-Lag Study

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

Rate Design

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

Vegetation Management, Quality of Service, and Service Regulations

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

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

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

Acceptance of Stipulation

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

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

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Basic Facilities Charge (BFC)

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

Customer Usage

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

Advanced Metering Infrastructure (AMI)

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

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

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

Customer Data

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

Power Forward and the Grid Rider

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

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

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

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Lee Nuclear

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

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

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

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

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

Nuclear Decommissioning Trust Fund (NDTF)

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

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

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

Depreciation

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

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

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

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

Tax Changes

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

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

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

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

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

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

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

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

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

Job Retention Rider (JRR)

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

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

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

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

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

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

CCR Cost Deferral

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

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

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

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

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

Recovery of CCR Costs

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

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

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

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

Provisional CCR Cost Recovery

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

CCR Allocation Guidelines

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

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

Insurance Litigation

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

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

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

Accounting for Deferred Costs

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

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

Revenue Requirement

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

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

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

Just and Reasonable Rates

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

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

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

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

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

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

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

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

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

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

Witness Fountain also outlined the coal ash basin closure costs the Company is seeking to recover in this case and emphasized that the Company is not seeking recovery of any costs incurred in response to the release of coal ash from the Dan River Steam Station in February 2014. Id. at 169-70, 173-77. The Company's Application also requests that the Commission permit DEC to cancel the Lee Nuclear Project as originally

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envisioned[6] and to recover costs for project development work completed for the project. Id. at 167-68. Finally, witness Fountain noted that the cost increases requested in this case are partially offset by the return of a deferred tax liability to customers. Id. at 170.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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Rate of Return on Equity

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

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

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

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

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

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

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

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

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

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

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

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

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

2013 DEP Rate Order, at 29.

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

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

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

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

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

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

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

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

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

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

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

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

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

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> been used widely for many years by regulatory commissions throughout the country in determining the rate of return allowed public utilities.
>
> In reality, the concept of a fair rate of return represents a "zone of reasonableness." As explained by the Pennsylvania commission:
>
>> There is a range of reasonableness within which earnings may properly fluctuate and still be deemed just and reasonable and not excessive or extortionate. It is bounded at one level by investor interest against confiscation and the need for averting any threat to the security for the capital embarked upon the enterprise. At the other level it is bounded by consumer interest against excessive and unreasonable charges for service.
>
> As long as the allowed return falls within this zone, therefore, it is just and reasonable. . . . It is the task of the commissions to translate these generalizations into quantitative terms.
>
> Charles F. Phillips, Jr., The Regulation of Public Utilities, 3d ed. 1993, pp. 382. (notes omitted).

2013 DEP Rate Order, pp. 35-36.

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

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

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

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

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

1. Evidence from Expert Witnesses on Cost of Equity Capital

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Witness Parcell also conducted a comparable earnings analysis examining the S&P's 500 Composite group. Over the same two business cycles, the group's average

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

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

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

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

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

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of the Stipulation are reasonable within a broad negotiation and resolution of many of the issues in this proceeding.

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

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

DEC witness Hevert also testified in support of the Stipulation on the agreed-upon rate of return on equity, capital structure, and overall rate of return contained in the Stipulation. He testified that although the stipulated rate of return on equity is below the lower bound of his recommended range of 10.25%, he recognized that the Stipulation represents negotiations among DEC and the Public Staff regarding otherwise contested

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issues. He testified that the Company has determined that the terms of the Stipulation, in particular the stipulated rate of return on equity and equity ratio, would be viewed by the rating agencies as constructive and equitable, and that he understands and respects that determination.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

2. Discussion of Rate of Return Evidence and Conclusions

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

The Commission determines the appropriate rate of return on equity based upon the evidence and particular circumstances of each case. However, the Commission believes that the rate of return on equity trends and decisions by other regulatory

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

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

3. Evidence of Impact of Changing Economic Conditions on Customers

As noted above, utility rates must be set within the constitutional constraints made clear by the United States Supreme Court in Bluefield and Hope. To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an

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unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting a return on equity, the Commission must nonetheless provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. State ex rel. Utils. Comm'n v. General Telephone Co. of the Southeast, 281 N.C. 318, 370, 189 S.E.2d 705 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return declared" in Bluefield and Hope. Id.

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

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

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

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

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

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

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

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

b. Evidence Introduced During Public Witness Hearings and Further Conclusions

The Commission's review also includes consideration of the evidence presented, primarily by way of non-expert witness testimony, at three evening hearings held throughout DEC's North Carolina service territory to receive public witness testimony. The public witness hearings held in this proceeding afforded 75 public witnesses, most of whom are customers of DEC, the opportunity to be heard regarding their respective positions on DEC's application for a general rate increase. The testimony presented at

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the non-expert witness hearings illustrates in detail the difficult economic conditions facing many DEC customers, and the witnesses' general objection to DEC recovering costs related to coal ash cleanup. More than 20 witnesses testified that the rate increase was not affordable for many customers, including those on fixed incomes, the elderly, persons with disabilities, the under- and unemployed, and the poor. Notably, a number of customers also expressed the view that the Company should be required to revise its current grid modernization plans in favor of increased energy efficiency and renewable energy resources initiatives. A representative sample of the public witness testimony received is summarized below.

Summary of Testimony Received in Franklin

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

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

Witnesses Sparks, Erickson, Horton, Crawford, Boyd, and Smith oppose a rate increase because, in their opinion, DEC's financial position is healthy enough such that a rate increase is unnecessary. Witnesses Sparks, Horton, Lawley, Zwinak, Wilde, Smith, and Corbin testified that customers living on a fixed or low income, including senior citizens and those living with disabilities, cannot afford a rate increase. Witness Wilde testified that "even [] a one cent increase in electric" costs would break the already stretched fixed-incomes of the elderly. Tr. Vol. 1, p. 64. After explaining that a number of counties across North Carolina face significant economic distress, witness Smith, a former Board Chair of the Jackson-Macon Conservation Alliance, expressed concern that

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the suggested rate hike would be "shared equally among all counties, despite enormous economic disparities." Id. at 66. Any rate increase, Mr. Smith concluded, would "translate to real sacrifices for working families" in those counties. Id. at 68. Witness Smith further testified that a rate increase would discourage energy efficiency and conservation measures.

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

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

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

Summary of Testimony Received in Greensboro

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

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

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

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

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

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

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

Summary of Testimony Received in Charlotte

Witnesses Kasher, Taylor, English, Nicholson, Satterfield, Brown, Hollis, McLaney, Moore, Henry, Sprouse, Blotnick, Copulsky, Jones, Segal, Lauer, Eddleman, and Mitchell testified that DEC's shareholders, and not its ratepayers, should be required to bear the costs of DEC's mismanagement in failing to properly handle and dispose of coal ash. Witnesses English, Nicholson, and Satterfield testified that allowing DEC to charge its ratepayers for coal ash cleanup would set problematic precedent in the event of future

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environmental issues. Witnesses Brown and Lauer testified to the direct impacts that DEC's coal ash mismanagements have had on their lives, including their water supply, and opined that it is wrong to ask those who have been directly harmed by DEC's coal ash management practices to pay more for their electric service. Witness Eddleman testified that DEC has "always refused to line their coal ash pits." Tr. Vol. 3, p. 115.

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

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

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

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

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

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

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

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

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

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

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

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

[12] N.C. Gen. Stat. § 62-133(c)

[13] N.C. Gen. Stat. § 62-133(b)(3).

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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

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consumers to pay in the current economic environment. While the equity investor's cost was calculated by resort to a rate of return on equity of 9.9% instead of 10.75%, this is only one approved adjustment that reduced ratepayer responsibility and equity investor reward. Many other adjustments reduced the dollars the investors actually have the opportunity to receive. Therefore, nearly all of these other adjustments reduce ratepayer responsibility and equity investor returns in compliance with the Commission's responsibility to establish rates as low as reasonably permissible without transgressing constitutional constraints.

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

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

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

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

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

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

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

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

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Summary and Conclusions on the Rate of Return on Equity

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

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

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

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

The Commission also concludes that the comparable earnings analysis by CUCA witness O'Donnell is credible, probative, and entitled to substantial weight. Witness O'Donnell testified that the comparable earnings for his and witness Hevert's proxy group of electric utilities produced earned returns of 9.25% to 10.25% over the period 2015

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through 2022, balancing historical and forecasted returns. The Commission-approved 9.9% rate of return on equity is well within that range.

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

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

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

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

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

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

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

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

The Commission gives no weight to any of the witnesses' CAPM analyses. The analyses of witness Parcell with a mid-point of 6.5% is unrealistically low, and witness Parcell agreed as much in his testimony. The CAPM analysis of witness O'Donnell resulted in a CAPM rate of return on equity mid-point of 6.29%, which is an outlier well below the 9.1% previously discussed. Witness Woolridge's CAPM weighted median rate of return on equity of 7.90% is also an outlier and unrealistically low. DEC Witness Hevert's CAPM range of 9.18% to 11.88% is also an outlier and upwardly biased due to witness Hevert's risk premium component of his CAPM using a constant growth DCF for

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the S&P 500 companies solely using analysts projected EPS forecasts as the growth component. Witness Hevert's DCF dividend growth, component based solely on analysts' EPS growth projections, without consideration of any historical results, is upwardly biased and unreliable.

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

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

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

Capital Structure

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

Witness De May testified that the Company's specific debt/equity ratio will vary over time, depending on the timing and size of debt issuances, seasonality of earnings,

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

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

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

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

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

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

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

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

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

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

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

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

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

Finally, the Commission has also carefully considered changing economic conditions in connection with its capital structure determination, including their effect upon the Company's customers. As discussed in the rate of return on equity section above,

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which is incorporated herein, the public witnesses in this case provided extensive testimony concerning economic stress they are currently experiencing and have experienced for the last several years. The Commission accepts as credible and probative this testimony. Likewise, the Commission gives significant weight to the testimony of witness De May regarding the Company's need to raise capital at this time to finance the improvements needed for safe, adequate, and reliable electric service.

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

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

Cost of Debt

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

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

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

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

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

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

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

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

Aviation Expenses

In its initial and revised supplemental filing, the Company removed 39.93% of the Company's O&M costs related to corporate aviation. Public Staff witness Boswell made a further adjustment after investigating the aviation expenses charged to DEC during the test year. Based on the Public Staff's review of flight logs, the corporate aircraft are available for use by Duke Energy Corporation's Chief Executive Officer (CEO) and DEC staff. The Public Staff recommended that certain expenses allocated to DEC be removed due to the nature of the flights involved. Tr. Vol. 26 p 591-92. For the purposes of settlement, the parties agreed to an adjustment that removes 50% of the Company's corporate aviation O&M expense.

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

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Executive and Incentive Compensation

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

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

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

As part of the Stipulation, the parties agreed to accept the Public Staff's adjustment with a modification to limit the incentives removed. This agreement is reflected in Section III.H. of the Stipulation, which provides that the Company's employee incentives should

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be adjusted to remove the cost of the STIP based on the Company's EPS for employees who qualify for the Company's LTIP.

Outside Services

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

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

Costs to Achieve Duke Energy-Piedmont Merger

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

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

(Emphasis added).

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

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

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

Sponsorships and Donations

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

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Lobbying and Board of Director Expenses

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

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

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

Allocations by DEBS to DEC

DEBS is the company that provides services to various affiliated entities of Duke Energy Corporation. The affiliated entities have a Cost Allocation Manual (CAM) that documents the guidelines and procedures for allocating costs between the entities to ensure that one entity does not subsidize another. As discussed above, during the test year, Duke Energy acquired Piedmont and the Commission approved the merger on September 29, 2016. According to Public Staff witness Boswell, this change, along with updates related to other affiliated entities, has caused the DEC allocation factors to decrease. Tr. Vol. 26, p. 595. Witness Boswell made an adjustment to reflect the fact that O&M expenses allocated to DEC from DEBS will be less going forward. Id. In her rebuttal testimony, witness McManeus explained that the Company did not agree with

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witness Boswell's adjustment because she included only three months of costs related to Piedmont, which results in a mismatch between the allocation factors and the costs to which they are being applied. Tr. Vol. 6, 323. In her supplemental testimony, witness Boswell updated the adjustment to include a full 12 months of the impact of the Piedmont acquisition into the adjustment and noted that the Company did not oppose this adjustment. Tr. Vol. 6, p. 617. As part of settlement, the parties agreed to accept the Public Staff's adjustment regarding the DEBS to DEC allocation as set forth in the supplemental testimony of Public Staff witness Boswell. Stipulation, § III.M.

Salaries and Wages

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

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

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

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

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the State EDIT to customers through a rider that would expire at the end of a two-year period. Tr. Vol. 26, p. 600.

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

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

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

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average expected annual O&M expenses associated with the project from 2018 through 2020. Id. at 264.

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

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

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

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

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

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

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

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

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

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

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

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

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

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the Public Staff agreed to hold the record open to allow the filing by the Company of an affidavit indicating that the plant has closed to service for operational and accounting purposes and that it is used and useful for the benefit of customers. Id.

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

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

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

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

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

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

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

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

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

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

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upon total of the approved base fuel and fuel related cost factors, by customer class, as set forth below (amounts are ¢/kWh excluding regulatory fee):

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

Tr. Vol. 6, p. 354.

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

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 27

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

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

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

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lower delivered fuel prices due to closer proximity to coal sources, combined with the efficiency of the Company's coal generation technology. Id. at 27.

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

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

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

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

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

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 28

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

Summer Coincident Peak

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

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

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

DEC's peak system demand for the test year, occurred on July 27, 2016, at the hour ending at 5:00 p.m. Id. This was also the peak generation and transmission demand used in the Company's cost of service study for the test year. Id. Witness Hager explained that the SCP in the test year is within the range of previous SCP occurrences, and it is

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therefore appropriate to assign fixed demand-related costs to the Company's jurisdictions and customer classes based upon the SCP. Id. at 26.

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

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

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

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

In arriving at its conclusion, the Commission finds that having the necessary generation and transmission resources to meet the Company's summer peak (plus an appropriate reserve margin) is an essential planning criteria of the Company's system. Under cost causation principles, therefore, all customer classes should share equitably in the fixed production and transmission costs of the system in relation to the demands they place on the system at the peak. As discussed and supported in DEC's integrated resource plans, the Commission also recognizes the Company's shift to winter capacity planning. This change will require more attention in the Company's next general rate

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case. The Kroger Co. in its post-hearing Brief stated that "[i]f the Commission determines that the winter peak should also be considered in the allocation of production demand costs, an allocator based on the average of the single highest summer and single highest winter coincident peaks may also be appropriate." See Post-Hearing Brief of the Kroger Co., p. 7. The Commission concludes that DEC should file annual cost of service studies based on Winter Coincident Peak as well as the SCP and SWPA methodologies. In its next general rate case, the Company shall prepare cost of service studies based on each of these methodologies.

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

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

Minimum System

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

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

Witness Hager also explained that while the NARUC Cost of Service Manual suggests two methods of allocation, both of these methods identify a portion of FERC distribution asset accounts 364 to 368 as customer-related and a portion as demand

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related. Id. at 38. Therefore, witnesses Barnes' and Wallach's suggestion that all of the costs charges to accounts 364 to 368 should be allocated based on demand is inconsistent with the guidance provided in the NARUC Cost of Service Manual. Id.

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

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

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

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

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

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

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

Further, witness Barnes stated in his testimony that:

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

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

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

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

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

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

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

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

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

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

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

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

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 30

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

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

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

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

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

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

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

AMI Enabled Rates

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

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

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

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

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

TOU or Critical Peak Pricing Rates

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

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

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

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

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

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

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

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

OPT-V Rate

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

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

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

The Commission finds and concludes that the Company's proposed OPT-V rate is just and reasonable in light of the evidence presented. The Commission, therefore, rejects witness Phillips' recommendation to reduce the proposed energy rates for Schedule OPT-V on the grounds that adjusting one pricing component without consideration of all pricing factors is inappropriate. It is appropriate to consider all pricing components,

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including marginal cost pricing, customer charge, as well as demand and energy charge, and balance these various components in order to set rates that send an appropriate price signal to customers. Applying that framework, the Commission finds and concludes that the Company's proposed OPT-V rate, including the proposed energy rate, strikes an appropriate balance of pricing factors and sends the correct price signal to customers.

Outdoor Lighting

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

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

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

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

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

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

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

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

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

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

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

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

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

Similarly, witness Watkins testified that the Company's LED transition fees and outdoor lighting rates make it "difficult for [the City of] Burlington and other municipalities to afford a complete conversion to LED lighting" which inhibits these municipalities from

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

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

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

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

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

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opportunity for more municipalities to participate in outdoor lighting discussions with the Company. Id.

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

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

The Lighting Settlement provides in pertinent part as follows:

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

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

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

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

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

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

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

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

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

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

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

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

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

Lighting Settlement, pp. 2-5.

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

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Standby Service

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

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

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

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

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

Id.

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

Summary with Respect to Rate Design

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

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

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

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

Id.

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

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

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

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1, and the testimony and exhibits of DEC

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witnesses Fountain, Simpson, Pirro and McManeus, and Public Staff witnesses Williamson and Boswell and the entire record in this proceeding.

Vegetation Management

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

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

Id. at 100-01.

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

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

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

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

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

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

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

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

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

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

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

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

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

Quality of Service

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

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

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

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

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

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

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

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

Service Regulations

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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proceeding.

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

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

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 36

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

Company witness Pirro explained that the Company proposes to increase (or decrease) the BFC for each rate class to better reflect the underlying cost of serving customers regardless of the customer's level of energy use. Tr. Vol. 19, pp. 60, 63. Pirro Exhibit 8 shows the Company's proposed BFCs, which are based on a percentage

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difference between the current BFC and the costs determined in the Company's cost of service study provided by witness McManeus. Id. at 63. Specifically, DEC proposes to increase the monthly BFC for the residential rate class, other than Schedule RT, from $11.80 to $17.79, which reflects approximately 50% of the difference between the current rate of $11.80 and the customer-related cost of $23.78 identified in the cost study. Id. at 60; Pirro Ex. 8. Although the Company's analysis supports increasing the residential BFC to $23.78, the Company has proposed a smaller increase to moderate any effect on low-usage customers. Id.

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

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

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

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

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residential customers with low usage are subsidizing larger customers under DEC's proposed rates. Id.

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

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

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

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

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

Id.

The AGO stated in its brief that:

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

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AGO's Brief, pp. 91-92.

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

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

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

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

Witness Pirro also responded to NC Justice Center, et al. witnesses Howat and Deberry's testimony regarding the disproportionate impact of an increased BFC on low-income customers. Witness Pirro explained that the Company is mindful of the impact of any rate increase on its customers, particularly low-income customers; however, the Company does not design rates based upon customer incomes, but rather applies cost

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causation principles to the extent practicable. Id. at 85. Witness Pirro explained that the Company uses other means to address the financial needs of low-income customers which are more effective than biasing the rate design, such as the Company's Residential Income Qualified Energy Efficiency and Weatherization Assistance Program, budget billing and payment arrangements, and Energy Neighbor Fund. Id. at 85-86.

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

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

Further, the Commission agrees with witness Pirro's testimony that shifting customer-related cost to the kWh energy rate further exacerbates these concerns and may over-compensate energy efficiency and distributed generation for the cost avoided by their actions. However, the Commission does not find sufficient support in this proceeding to increase the BFC to $17.79 as proposed by the Company. Rather, the Commission in this proceeding finds, in response to parties resisting any increase in the BFC, that the modified increase in the residential BFC is appropriate. The Commission finds and concludes that it is just and reasonable that the BFC for other non-residential rate schedules shall be left unchanged at this time based upon the evidence in the record. In support of these conclusions, the Commission notes that other non-residential rate schedules are more complex, thus allowing for the minimization of cost-subsidization issues and ensuring greater consistency with cost causation and allocation principles. In addition, the Commission notes that a greater amount of fixed costs in the residential rate schedule, as opposed to non-residential rate schedules, presently are recovered through

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variable energy rates, which is inconsistent with basic cost allocation principles that fixed costs should be recovered through fixed charges, whereas variable costs should be recovered through variable charges. The Commission further notes that it likely will review and evaluate several competing theories on this issue in the near future, when a docket is created to review net metering rate schedules pursuant to the directive set forth in House Bill 589. Finally, although the parties dispute the extent to which the residential class should bear responsibility for fixed or demand related costs, the $14.00 charge the Commission approves lies within the range of the charges advocated by the parties. In its discretion, the Commission determines that $14.00 is the appropriate charge for purposes of this case. While DEC's evidence would support a higher charge, the Commission determines that cost causation analyses are inherently subjective and selecting a charge within the range advocated based on differing cost causation models is appropriate.

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 37

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

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

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

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

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

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

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

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

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growth adjustment. Id. In his supplemental testimony, witness Saillor incorporated customer data for the month of December 2017 in his customer growth analysis. Tr. Vol. 26, p. 911.

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

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

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

Proceedings in Docket No. E-100, Sub 147

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

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

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

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

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

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

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

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

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

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of March 31, 2017. In Exhibit A, Appendix C, DEC provided its AMI cost-benefit analysis, which was the same analysis that DEC filed as a part of its supplemental information filing on May 5, 2017.

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

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

Summary of AMI Testimony

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

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

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

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

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

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

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

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

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meter reading and mass meter interrogation capabilities, which allow the Company to quickly assess outages and restore power more efficiently. Id. at 335-37.

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

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

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

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

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

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

Summary of Post-Hearing Briefs

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

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

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

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

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

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

Tr. Vol. 23, p. 89.

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

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

Discussion and Conclusions

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

A. Reasonableness of AMI Costs

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

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

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

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

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

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

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

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

Supplemental Filing, p. 1.

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

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

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

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

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

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

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

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

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

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

B. Appropriate Remaining Useful Life for AMR Meters

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

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

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

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 41

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

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

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

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

The Commission appreciates the recommendation of NCSEA and EDF regarding the collection and dissemination of customer usage data. However, the Commission is not persuaded that this is the time or the proceeding in which to impose such requirements on the Company. As witness Hunsicker testified, the Commission and

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interested parties are addressing issues regarding access to customer usage data in Docket No. E-100, Sub 147. In that docket, on March 7, 2018, the Commission issued an order on DEC's and DEP's (collectively, Duke's) 2017 Smart Grid Technology Plan (SGTP) Updates that included the following directive on access to customer data:

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

2017 SGTP Order, at 10.

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

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

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

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

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

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

Summary of the Evidence

DEC's direct testimony

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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proceed with Power Forward as planned, within the same time frame, even without approval of the Grid Rider.

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

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

Public Staff testimony

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

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

In 2003, the Public Staff prepared a report on the feasibility of undergrounding the State's entire distribution grid for the North Carolina Natural Disaster Preparedness Task Force (2003 Report). Tr. Ex. Vol. 24, pp. 116-164. The 2003 Report found that undergrounding the entire distribution grid was too costly and recommended instead that each utility (1) identify the overhead facilities that repeatedly experience reliability

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problems; (2) determine whether conversion to underground is a cost-effective option for improving the reliability of those facilities; and, if so, (3) convert those facilities to underground.[30]

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

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

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

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

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

Testimony of other intervening parties

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

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

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

[31] See Senate Bill 619 (2017).

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

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

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

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

NCSEA witness Golin recommended that the Commission deny the Company's proposal to recover Power Forward costs through either the Grid Rider or deferral accounting. She stated that the Commission should instead open a stand-alone docket to thoroughly define and plan for a modernized grid. In so doing, witness Golin stated that the Commission should require DEC to conduct robust distribution resource

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planning and take a holistic view of the grid and the technologies that are capable of meeting the grid's needs. This, according to witness Golin, would assure proper forecasting, better evaluate the role of distributed energy resources, and allow for increased transparency and stakeholder input. "Distribution resource planning should be accompanied by thorough cost/benefit analyses that compare several investment pathways to meeting grid investment goals." Tr. Vol. 14, p. 70. Witness Golin recommended that, as part of a new proceeding to examine Power Forward, participants could determine a method and timeline for calculating and publishing the distributed generation hosting capacity of DEC's distribution circuits. Witness Golin also advocated that the Commission open a new docket or stakeholder working group "to assess the impacts of shifts in the Company's investment strategy with the current mechanisms for cost recovery and implications for rate design." Id.

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

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

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

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DEC's rebuttal testimony

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

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

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

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

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

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

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

Id. at 165-66.

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

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

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

In response to several intervenors' suggestions that a separate proceeding is needed to fully evaluate DEC's Power Forward initiative, witness Simpson disagreed because "[Power Forward] is no different from the grid planning the Company has [sic]

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done for years, but this initiative is more comprehensive in scope and period than is typical." Id. at 193. In addition, witness Simpson referenced the Technical Workshop that DEP was ordered to hold in early 2018. He again referred to the annual Grid Rider proceeding, which he said would be the avenue through which the Commission and intervening parties could evaluate DEC's Power Forward plans and expenditures.

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

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

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

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

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

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

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

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

Commission Determinations

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

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

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

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A. No exceptional circumstances exist to justify the Grid Rider

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Id.

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

For example, monitoring, maintaining, and replacing aging equipment with like or new components, regardless of the pace at which these activities are conducted, is part

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of the Company's ongoing obligation to provide adequate and reliable electric service. In addition, the Commission concludes that new data analytics tools that DEC is using to identify the line segments in its Targeted Underground program do not make the program itself an extraordinary or unique modernization project. Undergrounding of lines is not a new concept, as conceded by DEC witness Simpson. Data analytics, as witness Simpson admitted, is neither a new phenomenon, nor is this current iteration of data analytics likely to remain unchanged for the foreseeable future.

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

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

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

Lastly, Enterprise Systems and Communications Network Upgrade programs include upgrades to several systems that the Company already uses to enable data acquisition and analytics to help control the grid. The Commission finds, therefore, that these upgrades are no different than many upgrades to other systems that the Company has made in the past and currently is in the process of making. One example is the Customer Connect program, which is an update to the existing customer information

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system and not included in Power Forward. The Commission considers these upgrades to constitute part of the ordinary evolution of the Company's business.

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

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

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

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

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

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

C. DEC shall utilize existing Commission dockets to collaborate with stakeholders

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

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

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

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D. The Pilot Grid Rider Agreement and Stipulation is disapproved

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

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

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

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

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

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

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

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

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

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

Generally speaking, under N.C. Gen. Stat. § 62-110.7(b), the Commission shall approve a utility's decision to incur project development costs if the utility demonstrates that the decision to incur such costs is reasonable and prudent; however, the Commission does not consider the reasonableness or prudence of any specific activities or items of costs until a rate case proceeding. North Carolina Gen. Stat. § 62-110.7(c) provides that reasonable and prudent project development costs shall be included in the utility's rate base and be fully recoverable through rates in a general rate case. However, if the project

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is cancelled, as has occurred in this case, N.C. Gen. Stat. § 62-110.7(d) allows the utility to recover all reasonable and prudently incurred project development costs in a rate case amortized over the longer of five years or the period during which the costs were incurred, which in this case is 12 years. It should be noted that while N.C. Gen. Stat. § 62-110.7(c) provides for rate base treatment of project development costs and therefore includes a return, N.C. Gen. Stat. § 62-110.7(d), applicable to cancelled projects, only requires amortization of the costs and does not mention, and certainly does not mandate, a return.[38]

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

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

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

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

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

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

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

In regard to the request to cancel the Lee Nuclear Project, witness Fallon said that since issuance of the COL, the risks and uncertainties in regard to beginning construction have become so great that cancellation was in the best interest of customers. Tr. Vol. 10, p. 195. He noted that in early 2017, Westinghouse announced its plans to exit the nuclear plant construction business, and then, on March 29, 2017, announced its bankruptcy. Tr. Vol. 10, p. 196. Additionally, the first two plants being constructed with AP1000 reactors, in South Carolina (V.C. Summer Project) and Georgia (Vogtle Project), have cost billions

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of dollars more than originally estimated and have faced significant delays. Id. Witness Fallon stated that the Westinghouse bankruptcy and the decision to stop construction at the V.C. Summer Project led to great uncertainty about the cost, schedule, and execution of construction for future nuclear projects, directly impacting the Lee Nuclear Project. Tr. Vol. 10, p. 198. Therefore, due to these uncertainties and risks, as well as projected low natural gas prices and uncertainty about carbon emission costs, witness Fallon testified that the Company thought that it is not in customers' best interest to construct and operate Lee Nuclear before the end of the next decade. Id. As a result, the Company requests to cancel the project, but maintain the COL. Tr. Vol. 10, pp. 198-99. Witness Fallon indicated that there would be post-COL costs of approximately $700,000 per year so the Company could make annual filings with the NRC and maintain the property. Tr. Vol. 11, p. 72.

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

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

Witness Diaz also reviewed the cost breakdown for the COL and project-related costs for the Lee Nuclear Project and found that they compared favorably to the costs incurred by Florida Power & Light (FP&L) for its Turkey Point Units 6 and 7 COL. Tr. Vol. 10, p. 249. He discussed the disadvantages that would have resulted if DEC had

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suspended its efforts to license Lee Nuclear, the value of the Lee Nuclear COL, the advantages of DEC's licensing-first approach, and the reasonableness of the selection of the AP1000 design. Tr. Vol. 10, pp. 250-51. Witness Diaz concluded that based on his experience, DEC's approach to licensing and managing the Lee Nuclear Project, and its decision to extend the targeted operation dates, were reasonable and consistent with best practices. Tr. Vol. 10, p. 253. He further determined that the project costs incurred were reasonable and prudent. Tr. Vol. 10, p. 234.

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

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

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

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

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

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He noted that the Public Staff hired as a consultant, Global Energy & Water Consulting, LLC, a firm with extensive experience with nuclear construction activities and NRC application processes, to (1) review the details of all costs charged to all the capital accounts assigned to engineering, licensing, and regulatory compliance for the Lee Nuclear Project; (2) review the decisions to begin, continue, and cancel the project, as well as issues with the AP1000 design, Westinghouse, and Westinghouse's owner, the Toshiba Corporation; (3) review DEC's project planning decisions; (4) compare the costs incurred to those of other utilities; and (5) identify any costs that were not reasonably or prudently incurred. Tr. Vol. 23, pp. 31-32. The Public Staff also reviewed the activities and costs internally. Tr. Vol. 23, p. 32. Based on the Public Staff's review as assisted by the consultants, the Public Staff found that with one exception involving design costs for a visitors' center, the costs incurred (not including AFUDC, which was reviewed by Public Staff witness Maness) were reasonably and prudently incurred based on information known at the time. Tr. Vol. 23, pp. 32-33. Witness Metz recommended that costs incurred for the architectural and engineering design of a visitors' center be disallowed on the basis that under the dictates of the 2011 Order, the costs did not directly support the COLA process at the NRC and were not necessary to maintain the status quo at that time. Tr. Vol. 23, pp. 33-34. This recommendation results in a disallowance of $507,009 on a system basis, exclusive of AFUDC. Tr. Vol. 23, p. 36.

Public Staff witness Maness testified that on behalf of the Public Staff, he investigated the reasonableness of the accrual of the AFUDC costs included in DEC's project development costs, and particularly DEC's dates for beginning and ending the accrual of AFUDC. Tr. Vol. 22, p. 100. Based on his review, witness Maness found the date on which DEC began accruing AFUDC to be reasonable, but recommended that AFUDC accrual end as of December 31, 2017, instead of the May 1, 2018, date estimated by DEC. Id. He testified that under FERC Accounting Release No. 5, AFUDC accruals must cease if construction is suspended or interrupted. Tr. Vol. 22, p. 101. Based on discussions between DEC and the Public Staff, witness Maness stated that the Company had confirmed that work on the Lee Nuclear Project had ended as of December 31, 2017, and that the Company had ceased accruing AFUDC at that time. Tr. Vol. 22, p. 102. He noted that removal of the estimated 2018 AFUDC from the costs proposed for Lee Nuclear recovery resulted in a $9 million adjustment. Id.

Public Staff witness Boswell contended that the Commission should adhere to its longstanding position that no adjustment should be allowed which would effectively enable the Company to earn a return on the unamortized balance of the construction costs of a nuclear plant that had been abandoned. Tr. Vol. 26, p. 140. She argued that the Commission has found in past cases that this treatment fairly allocated the loss between the utility and customers, and that customers should not bear all the risk of the cancelled plant. Id.

In his rebuttal testimony, witness Diaz disagreed with witness Kee's stratification of costs into two categories on the basis that both types of costs were necessary for the Company to adhere to the 2011 Order and to have the Lee Nuclear option available to meet the dates for need projected in DEC's IRPs. Tr. Vol. 26 p. 181. He noted that DEC

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could not have obtained the COL without exceeding the limits in the 2011 Order. Tr. Vol. 26, p. 182. Witness Diaz further testified about the value of the COL obtained by DEC. Tr. Vol. 26, pp. 186-88.

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

Witness Fallon opposed the recommendation of Public Staff witness Boswell that DEC should not receive a return on the unamortized balance of the Lee Nuclear costs and associated accumulated deferred income taxes (ADIT). He noted that while witness Boswell referred to the costs of Lee Nuclear as having been prudently incurred, the financing costs of the unamortized balance were also prudently incurred costs. Tr. Vol. 24, pp. 34-35. Witness Fallon pointed out that N.C. Gen. Stat. § 62-110.7 does not prohibit DEC from receiving a return on the unamortized balance of prudently incurred costs. Tr. Vol. 24, p. 36. He argued that witness Boswell had not considered the specific facts of this case in making her recommendation of no return, including the fact that the Company had obtained a COL, the highly dynamic energy future, the advantages of maintaining fuel diversity, and the uncertainty of nuclear relicensing. Tr. Vol. 24, pp. 37-39. Witness Fallon also detailed the steps the Company took to mitigate the risks of the project. Tr. Vol. 24, p. 39.

In regard to the testimony of Tech Customers witness Kee, witness Fallon disagrees with the contention that all nuclear development costs must be approved or authorized in advance under N.C. Gen. Stat. § 62-110.7 to be recoverable. Tr. Vol. 24, p. 40. Witness Fallon noted that while the project development orders (PDOs) issued in Sub 819 have specific authorizations, they do not foreclose the possibility that DEC may recover costs outside of the strictures of those Orders. Tr. Vol. 24, p. 41. He also stated that utilities are permitted, but not required, to seek approval of the decision to incur project development costs under N.C. Gen. Stat. § 62-110.7, and that the Commission did not approve DEC's request for approval to incur Lee Nuclear costs in 2010, but it made no finding as to their recoverability. Id. Witness Fallon testified that DEC had exceeded the spending cap set in the 2011 Order. However, he testified that DEC interpreted the 2011 Order as requiring the Company to limit its spending to amounts necessary to preserve the option of building Lee Nuclear so that it would be available to meet the target dates of need set out in DEC's IRPs, including maintaining an active COLA at the NRC. Tr. Vol. 24, p. 44. In order to maintain this active COLA status, witness Fallon explained that DEC had to continue its permitting, pre-construction, engineering, design, construction planning, and operational planning activities to maintain the status quo. Tr. Vol. 24, p. 45. Further, witness Fallon testified that it was necessary for DEC to continue its efforts in many areas to avoid signaling to the NRC that DEC was not actively

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pursuing the Lee COL, which could have resulted in termination of the review process by the NRC prior to the issuance of the COL. Id.

On cross-examination, witness Fallon identified Tech Customers Fallon Rebuttal Exhibit 1 as an internal presentation made in February 2012 to the Company CEO's staff by himself and the nuclear development staff regarding the future of the Lee Nuclear Project. Tr. Vol. 24, p. 54. The exhibit showed the projected dollars spent that exceeded the limits of PDOs issued by the NCUC and the South Carolina Public Service Commission. Tr. Vol. 24, p. 56. The presentation indicated that filing for a subsequent PDO would put the NCUC in a "difficult position" as James E. Rogers, the CEO during the 2011 proceeding had testified that DEC would not proceed with Lee Nuclear unless the North Carolina General Assembly had enacted legislation allowing DEC to receive CWIP costs through a specified cost recovery process.[39] Tr. Vol. 24, p. 57. The presentation also noted the negative impact on the Lee Nuclear business case of projected low natural gas prices. Id. The presentation also pointed out the negative effect on the Lee Nuclear project that would result from a rejection of a further request for approval to incur nuclear development costs. Tr. Vol. 24, p. 58. Based on these factors, Nuclear Development recommended in 2012 that the Company not seek an additional PDO. Id. The Company also had another internal meeting in early 2013 where it again decided against pursuing a further PDO for similar reasons, as well as delays occurring with the NRC process. Tr. Vol. 24, pp. 62-64. Following the merger of Duke Energy Corporation and Progress Energy, Inc., a third senior management meeting was held in November 2013 to consider whether to pursue a PDO. Tr. Vol. 24, pp. 65-66.

Witness Fallon agreed that one of the purposes of N.C. Gen. Stat. § 62-110.7 is to help alleviate some portion of the risk that certain costs incurred for nuclear project development activities may be found to be imprudent. Tr. Vol. 24, p. 71. Witness Fallon stated that he was the Company witness supporting DEP's request in its recent rate case to recover COLA costs of approximately $45.3 million for its cancelled Harris Nuclear project. Tr. Vol. 24, p. 74. In that case, DEP did not seek a return on the unamortized balance of the costs for the COLA for the cancelled Harris Nuclear project. Tr. Vol. 24, p. 75. However, witness Fallon argued that the Harris Nuclear and Lee Nuclear projects are different because DEC had sought approval for the Lee Nuclear Project under N.C. Gen. Stat. § 62-110.7, the Lee Nuclear project had progressed beyond the development stage to receipt of a COL, and that the investor risk differed due to the amount of spending and the scope of activities. Tr. Vol. 24, pp. 75-77. Finally, witness Fallon acknowledged that while having the COL means that DEC may use its option to build the Lee Nuclear plant when the time is right, the time may never be right. Tr. Vol. 24, p. 82.

In her rebuttal testimony, Company witness McManeus noted that the Company did not oppose the recommendations of Public Staff witness Metz to remove certain costs associated with the design of a visitors' center from the Lee Nuclear costs or Public Staff witness Maness to remove AFUDC for the months after December 2017. Tr. Vol. 26,

[39] This testimony by Mr. Rogers was one of the factors cited by the Commission in its decision to issue only a limited approval of DEC's decision to incur project development costs in the 2011 Order.

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p. 310. She testified that the Company did oppose the adjustment recommended by Public Staff witness Boswell to remove the unamortized balance of deferred project development costs and the associated ADIT from rate base, thereby preventing the Company from earning a return on the unamortized balance. Id. Witness McManeus argued that the Commission should consider that the Lee Nuclear project costs were financed by investors and should appropriately be in rate base. Tr. Vol. 6, p. 311. According to witness McManeus, if the Commission determines that the Lee Nuclear costs were incurred prudently, it should include those costs in rate base, thereby allowing the Company to earn a return on the unamortized balance. Id. On cross-examination, witness McManeus agreed that the decision to allow the Company to earn a return on cancelled plant was within the Commission's discretion. Tr. Vol. 8, p. 232. She further agreed that once the amortization of Lee Nuclear was completed, it would be inappropriate for the Company to re-establish the asset and thus recover it from the customers again. Tr. Vol. 26, p. 110. She indicated that if recovery of Lee Nuclear costs were allowed, DEC would have a regulatory asset that would be amortized over the period allowed, and then in DEC's next rate case, the balance of the regulatory asset would be addressed. Id.

Discussion and Conclusions on Lee Nuclear

A. Recovery of Costs

In regard to specific items of cost, the Commission agrees with Public Staff witness Metz that costs incurred for the architectural and engineering design of a visitors' center did not directly support the COLA process at the NRC and were not necessary to maintain the status quo at that time as directed by the 2011 Order. As such, these costs should be disallowed. The Commission also agrees with Public Staff witness Maness that accrual of AFUDC on the project should have stopped after all substantive work on the project had come to an end by December 31, 2017. As noted above, DEC did not contest either of these two proposed adjustments.

As noted above, Tech Customers witness Kee recommended disallowance of the costs incurred in 2010 and the costs in excess of the limit set in the 2011 Order. In its proposed order, Tech Customers supports this position. NC WARN supports the recommendations of witness Kee in its brief. In its proposed order, the AGO argues that given the evidence challenging the reasonableness and prudence of DEC's expenditures on and after January 1, 2011, and DEC's failure to provide details sufficient to identify what it would have cost to maintain the status quo, the costs incurred on or after January 1, 2011 for new development activities should be disallowed. The Commission finds that witness Kee's recommendation appears to be based on a misinterpretation of N.C. Gen. Stat. § 62-110.7. First, N.C. Gen. Stat. § 62-110.7(b) includes the word "may" indicating that it is at the utility's discretion whether it will seek to incur approval of its decision to incur nuclear project development costs under the statute. Costs for which preapproval is not sought, such as those in 2010, are still appropriately considered in a general rate case proceeding under N.C. Gen. Stat. § 62-133, including the prudence of the decision to incur the costs. Similarly, the costs that were incurred outside the cap set in the

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2011 Order are appropriately considered in this proceeding. N.C. Gen. Stat. § 62-110.7 provides a utility approval only of its decision to incur nuclear development costs under the circumstances at the time of the decision. No particular costs are approved or found to be reasonable, and circumstances can change after issuance of the approval making it no longer reasonable to incur costs. As discussed by DEC witness Fallon, DEP elected to pursue development of its Harris Nuclear project without obtaining approval under N.C. Gen. Stat. § 62-110.7 and the Commission approved recovery of the costs of the COLA in DEP's recent rate case without regard to whether DEP had received approval under N.C. Gen. Stat. § 62-110.7. The Commission further disagrees with witness Kee that what he categorizes as Type 2 costs should be disallowed because they were not necessary to maintain the status quo. The Commission finds that, except as discussed above in regard to the visitors' center and AFUDC, the costs were reasonably and prudently incurred to maintain the status quo and ensure that Lee Nuclear would be an option for the dates of projected need in DEC's IRPs.

B. Cancellation of the Lee Nuclear Project

The Company has stated that it seeks Commission approval to cancel the Lee Nuclear Project. The Commission agrees with DEC witness Fallon that the risks and uncertainties in regard to beginning construction of the Lee Nuclear Project, including the Westinghouse bankruptcy, issues with Toshiba, the cancellation of the Summer project, overruns and delays at the Vogtle project, as well as natural gas prices and potential carbon emissions regulation, have become so great that cancellation is in the best interest of customers. Further, DEC's 2017 IRP does not show a need for the first unit until 2031, and then only under a number of assumptions.

While no party expressed opposition to DEC's decision to cancel the Lee Nuclear Project, in their proposed orders, the Tech Customers and the Public Staff question the authority of the Commission to cancel the project noting that the Commission had never granted the project a CPCN under N.C. Gen. Stat. § 62-110.1, nor had any other state approved the project. While there may be merit to such observations, suffice it to say, the Commission finds and concludes that adequate justification exists to support cancellation of the Lee Nuclear Project and that DEC's decision to cancel the project is reasonable and prudent and in the public interest.

C. Return on Unamortized Balance

The Commission is also in agreement with Public Staff witness Boswell's position concerning the Company's request to earn a return on the unamortized balance of the costs. Company witness McManeus acknowledged on cross-examination that in the cases of Duke Power Co., Docket No. E-7, Sub 338, 72 N.C.U.C. 173 (Nov. 1, 1982); Carolina Power & Light Co., Docket No. E-2, Sub 461, 73 N.C.U.C. 114 (Sept. 19, 1983); and Carolina Power & Light Co., Docket No. E-2, Sub 481, 74 N.C.U.C. 126 (Sept. 21, 1984), all involving abandoned nuclear plants, the Commission had refused to allow a return on the unamortized balance. She further stated that she knew of no other case decided since 1982 approving a return on the unamortized balance; and neither the Public

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Staff nor the Commission has been able to identify any such case. The Commission's 1982-84 decisions denying a return on the unamortized balance of nuclear plant costs have been reaffirmed in cases such as Carolina Power & Light Co., Docket No. E-2, Sub 537, 78 N.C.U.C. 238 (Aug. 5, 1988), aff'd in part, rev'd in part on other grounds, and remanded sub nom. State ex rel. Utils. Comm'n v. Thornburg, 325 N.C. 484, 385 S.E.2d 463 (1989). See also, State ex. rel. Utils. Comm'n v. Thornburg, 325 N.C. 463, 480-81, 385 S.E.2d 460-61 (1989), which held that the Commission had the legal authority to deny a return on the unamortized balance of nuclear cancellation costs.

In the Commission's judgment, the decisions it has reached on this issue since 1982 are correct and should be followed in this case. The Commission has repeatedly decided that the loss experienced upon the cancellation of a nuclear plant should be shared between the shareholders and the ratepayers. As the Commission stated in its Order in Duke Power Co., Docket No. E-7, Sub 358, 73 N.C.U.C. 255, 266 (Sept. 30, 1983), when addressing the loss associated with the Cherokee Nuclear Plant (Lee's precursor abandoned nuclear project at the same site):

> It would be inequitable to place the entire loss of expenditures that were prudent when made on the utility. Thus, amortization should be allowed. However, on the other hand, the ratepayer must not bear the entire risk of the Company's investment. A middle ground must be found on which the Company bears some of the risk of abandonment and the ratepayer is protected from unreasonably high rates.

See also, In re Carolina Power & Light Co., Docket No. E-2, Sub 461, 55 P.U.R. 4th 582, 601 (1983).

Accordingly, regulatory commissions in North Carolina and many other states have allowed the utility to recover the costs of an abandoned plant through amortization, while excluding the unamortized balance from rate base. In this way, a fair allocation of the losses is accomplished: the ratepayers are required to bear the losses resulting directly from the cancellation, while the shareholders must absorb the loss associated with the delay in receiving their compensation. This is the policy that the Commission adopted in Duke Power Company's case in November 1982; we have consistently adhered to it in the years since, and we see no valid reason to depart from it now.

The Commission does not agree with witness Fallon that the Company's receipt of three PDOs should factor into whether it should receive a return. The Commission notes that the Company chose to act without a PDO in 2010 and after the second quarter of 2013, over one third of the period of the project, thereby acting outside of the requirements of and protections offered by N.C. Gen. Stat. § 62-110.7. While N.C. Gen. Stat. § 62-110.7 is permissive and the Commission has found that the Company's Lee Nuclear incurred costs and activities were reasonable and prudent (except as discussed above in regard to the visitors' center and AFUDC) regardless of whether it received PDOs for the entire period, DEC's receiving Commission approval of some of its decisions to incur nuclear project development costs does not factor into the Commission's exercise

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of its discretion under N.C. Gen. Stat. § 62-110.7(d) as to whether the Company should get a return on the unamortized balance of the Lee Nuclear costs.

Additionally, the Commission rejects the contention by witness Fallon that having obtained a COL should merit shifting the entire burden of cost and risk to ratepayers. While the Commission agrees that the COL has value, that value will only be realized if the plant is built. Pursuant to the 2017 IRP, that possibility would occur only under very limited circumstances. Moreover, there is a cost to maintaining this option that DEC will likely be requesting ratepayers to bear in future rate cases.

Further, in Docket No. E-2, Sub 1035, DEP sought a deferral on its Harris COLA costs, but requested no return on the unamortized balance, citing State ex rel. Utils. Comm'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 the 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 the unamortized balance). The Commission sees no reason to treat the Lee Nuclear Project differently, regardless of the difference in costs or achievement of a COL.

The Commission also notes that in its proposed order, for the first time in this proceeding, DEC argues that the Commission specifically made a distinction that it would treat the Lee Nuclear project development costs differently for purposes of ratemaking in its 2007 Order and that the General Assembly codified that distinction when it did not prohibit a return on the unamortized balance of prudently incurred costs during the amortization of a cancelled plant in N.C. Gen. Stat. § 62-110.7(d). In fact, DEC now argues that the principles of statutory construction that it weaves between N.C. Gen. Stat. § 62-110.7(c) and 110.7(d) support the Company's position that it should earn a return on the costs invested to develop the Lee Nuclear Project, even though it is cancelled. With respect to DEC's argument in these regards, the Commission simply disagrees. First, the Commission can unequivocally state that nothing in its 2007 Order spoke directly to or implied support for the Company to be able to earn a return on the unamortized balance. The Commission also notes that DEC's own witnesses testified that it was within the Commission's discretion whether or not to allow a return on the unamortized balance. Further, since the Lee Nuclear Plant is now cancelled, the term "…the potential nuclear plant…" that appears in N.C. Gen. Stat. § 62-110.7(c) is no longer applicable to the issue at hand, and N.C. Gen. Stat. § 62-110.7(d) is now controlling and there is no mention in N.C. Gen. Stat. § 62-110.7(d) regarding a return on the unamortized balance. In addition, although not applicable here, N.C. Gen. Stat. § 62-110.6(e), regarding rate recovery for construction costs of out-of-state electric generating facilities that are cancelled, directs the Commission to provide cost recovery as provided in N.C. Gen. Stat. § 62-110.1(f2) and (f3). N.C. Gen. Stat. § 62-110.1(f2) and (f3) include the

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provision that "…the Commission shall make any adjustment that may be required because costs of construction previously added to the utility's rate base pursuant to subsection (f1) of this section are removed from rate base and recovered in accordance with this subsection." (emphasis added) This analogous portion of the statute makes clear that costs associated with canceled plant are not part of rate base and the Commission determines to interpret N.C. Gen. Stat. § 62-100.7 which is silent as to the issue similarly. In summary, the Commission has carefully reviewed DEC's contentions that any prior Commission order or the ratemaking treatment prescribed in N.C. Gen. Stat. § 62-110.7(c) is supportive, applicable, or controlling with respect to allowing a return on the unamortized balance and disagrees.

Finally, although not discussed in the record, the Commission notes that during the entire 12-year period in which DEC incurred and funded the project development costs, it was allowed to accrue an AFUDC return. In fact, AFUDC comprises over forty percent of the total Lee Nuclear project development cost. The accrual of the AFUDC has already provided DEC, or its investors, a return on all non-AFUDC costs incurred during the past 12 years and that return will be recovered in cash from ratepayers over the next 12 years as the total allowed cost is amortized. The Commission concludes this consideration is supportive of its decision to require a fair allocation of costs for the cancelled plant between the Company and its ratepayers by denying a return on the unamortized balance during the 12-year amortization period.

D. Summary of Conclusions on Lee Nuclear

In summary, the Commission concludes in regard to the Lee Nuclear Project that the costs were reasonably and prudently incurred except the costs of the architectural and engineering design of a visitors' center and AFUDC after December 31, 2017. The Commission finds that it is reasonable and prudent for the Company to cancel the Lee Nuclear Project at this time. Finally, the Commission holds that the costs of the Lee Nuclear Project should be recovered through amortization over a period of 12 years, with no return on the unamortized balance.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 50-51

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1, the direct testimony of Public Staff witnesses Robert Hinton and Michael Maness, the rebuttal testimony of Company witnesses Stephen De May and David Doss, and the entire record in this proceeding.

Background of the Nuclear Decommissioning Trust Fund

Every nuclear power plant owner in the United States is required under rules promulgated by the NRC to ensure that the nuclear plants it owns and operates are properly decommissioned when they reach the end of their useful lives. Monies to pay for decommissioning activities are collected from customers in rates and deposited in trust funds, where they are invested and earn returns.

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DEC operates seven nuclear-powered units at three different power plants. Funds the Company has collected in rates from customers over the years, pursuant to specific authorizations contained in rate orders issued by this Commission, have been deposited in nuclear decommissioning trust funds (while each nuclear unit has its own decommissioning funds held in trust, for ease of reference, they are herein referred to collectively as the (NDTF)) pursuant to the NRC rules. Under those rules, as well as rules promulgated by the IRS, NDTF funds are to be used exclusively for nuclear decommissioning activities, which include license termination, dealing with spent fuel, and site restoration.

Through procedures described in greater detail below, every five years the Company engages a third-party consultant to perform a site-specific study and prepare a site-specific estimate of the decommissioning costs which will be necessary to decommission the units DEC owns and operates. Based upon that study, the Company files a report setting out those estimates (the Decommissioning Cost Study Report, or Cost Report). Every five years, based upon financial assumptions provided by additional third-party consultants, the Company models NDTF balances at the time of decommissioning and files a report in a prescribed format (the Decommissioning Cost and Funding Report, or Funding Report) detailing the total revenue requirement/decommissioning expense needed to fund its decommissioning obligations.

The Company last filed a Cost Report and Funding Report in 2014. Those Reports indicated that based upon projected decommissioning costs and projected NDTF balances (both projected decades into the future, inasmuch as decommissioning will not take place until decades into the future), the NDTF was adequately funded. Tr. Vol. 12, p. 48. Accordingly, the Company concluded that, at least as of that time, the Company need not collect in rates any cost with respect to nuclear decommissioning, and that additional contributions to the NDTF need not be collected from customers. The Company has not collected any NDTF contributions from customers since January 1, 2015.

Thereafter, with the joint support of the Company and the Public Staff, the Commission implemented a decrement rider as of July 1, 2015, reducing the Company's revenue requirements in order to reflect nuclear decommissioning costs at $0. In this rate case, based upon standard escalations of the 2014 Cost Report and 2014 Funding Report, the Company again concluded that the NDTF was adequately funded and determined that it need not collect any nuclear decommissioning expense as part of its cost of service.

In this docket, the Public Staff has taken the position that the NDTF is overfunded by $2.35 billion. The Public Staff asserts that in order to redress this supposed overfunding, the Company should be required to refund the excess by assigning to nuclear decommissioning "expense" a value of ($29 million) – that is, negative $29 million – per year. Acknowledging that the funds in the NDTF are untouchable for this purpose, in that they are to be used solely for decommissioning, the Public Staff developed a proposal by which the funds would be refunded to customers through the mechanism of a "loan" to be "repaid" after decommissioning is complete.

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DEC contends the NDTF is not "overfunded." Further, as discussed below, under generally accepted accounting principles (GAAP), the Company believes it would have to write off the proposed "loan" inasmuch as it would not have a probable and acceptable path to repayment. DEC also argues that the approach recommended by the Public Staff is retroactive in nature, thus violating the prohibition against retroactive ratemaking in North Carolina. Finally, DEC submits prior orders of this Commission including prior agreements between the Public Staff and the Company appropriately provide for addressing surplus decommissioning funds – if any – at the conclusion of decommissioning.

Summary of Evidence Relating to NDTF

On July 25, 1988, the Commission opened Docket No. E-100, Sub 56 (Sub 56 Docket) to consider issues relating to decommissioning cost and funding for nuclear power plants owned and operated by the public utilities under its jurisdiction, namely Carolina Power & Light Company (now DEP), Duke Power Company (now DEC), and North Carolina Power (now Dominion North Carolina Power).[40]

On November 3, 1998, the Commission issued an Order in the Sub 56 Docket (Order Approving Guidelines (DEC – Maness Cross-Examination Ex. 1, Tab 1)), in which it adopted guidelines for the determination and reporting of nuclear decommissioning costs (the Guidelines). The Guidelines establish the five-year cycle of report filing described above, with respect to both the Cost Report, where the Company estimates decommissioning costs, and the Funding Report, detailing the total revenue requirement/decommissioning expense needed to fund the Company's decommissioning obligations. Further, as Public Staff witness Maness confirmed, the Public Staff is provided a 90-day period to issue discovery and investigate the cost and funding analysis the Company sets out in its Reports. Tr. Vol. 22, pp. 185-86. The Public Staff then has 90 days to prepare and file its own report. Id. In accordance with the Guidelines, the Public Staff has routinely reviewed the Company's decommissioning Cost Reports and decommissioning Funding Reports.

In the Company's last rate case, it proposed that nuclear decommissioning expense be $35 million. See 2013 DEC Rate Order, p. 110; DEC – Maness Cross Examination Ex. 1, Tab 3. The Public Staff, through witness Hinton, proposed an adjustment to reduce that expense to $14.6 million, which the Company accepted and the Commission ordered. Id. at 111. In the following year, the Company's five-year Cost Report/Funding Report cycle required it to file those Reports. As noted above, the Company concluded in connection with those filings that the NDTF was adequately funded and that a decrement rider to reduce nuclear decommissioning expense to $0 as of January 1, 2015 was warranted, which the Commission ultimately ordered. DEC – Maness Cross Examination Ex. 1, Tabs 2 and 4; Tr. Vol. 22, pp. 189-92.

As required by the Guidelines, the Public Staff investigated the 2014 Cost Report and the 2014 Funding Report, as well as the Company's suggestion that nuclear

[40] The Chairman ruled that the Commission would take judicial notice of the filings in the Sub 56 Docket in this proceeding. Tr. Vol. 22, p. 183.

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decommissioning expense be reduced to $0 through a decrement rider. Tr. Vol. 22, p. 193. Its investigation was thorough, and the report that it prepared pursuant to the Guidelines was likewise thorough and well thought-out. Id. at 194. In that report (Public Staff Report; DEC – Maness Cross-Examination Ex. 2), the Public Staff noted that the NDTF fund balance would exceed estimated decommissioning costs at license termination[41] on a North Carolina retail jurisdictional basis by $2.5 billion. Id. at 11-12. The Report further indicated in its "Conclusions and Recommendations" section that the Public Staff had completed its investigation of the Cost Report and the Funding Report, had reviewed the Company's responses to data requests, and had no disagreement with the Company "regarding the calculation and implementation of the $0 expense/revenue requirements or any other aspect of its decommissioning cost and funding activity." Id. at 12. The Public Staff Report then concluded that apart from the implementation of the decrement rider, "the Public Staff has no recommendations for further action by the Commission in this matter." Id. (emphasis added).

In this rate case, the Company again determined that the nuclear decommissioning expense in its cost of service was $0. Tr. Vol. 12, p. 49. The Public Staff, however, asserted, through witness Hinton, that the NDTF was overfunded by $2.35 billion. Tr. Vol. 22, p. 252. The Public Staff proposed that these "excess" funds be returned to customers, and that this could be accomplished by reducing North Carolina retail expense by $29.1 million. Id. at 260.[42]

Under applicable NRC and IRS regulations, these funds could not be simply withdrawn from the NDTF, a fact recognized by Public Staff. Id. at 252. It indicated instead, through witness Maness, that if the Company "cannot remove such funds from the NDTF, its shareholders will be required to provide (i.e., loan) the funds for the expense reduction …." Id. at 105 (emphasis added). Witness Maness added that this loan would be "on a temporary basis." Id. Company witness Doss testified, "if the Public Staff's recommended rate-making mechanism is approved, and if actual experience mirrors the projections on which the Public Staff's recommended refunds are based, the Company would not be entitled to collect on the loans to ratepayers until funds could be withdrawn from the NDTF upon the completion of nuclear decommissioning activities, which is currently expected to occur in approximately 50 years." Tr. Vol. 12, p. 60.

Discussion and Conclusions

The key factual predicate to the Public Staff's recommendation is that the NDTF is overfunded. The facts in this case indicate that it is premature to reach such a conclusion. The Public Staff's principal proponent of the notion that the NDTF is overfunded – witness Hinton – did not testify that this is the case in absolute terms. Rather, his testimony is hedged with qualifiers: "Assuming the projected decommissioning costs and earning returns … are

[41] Measurement at license termination is the manner in which the Guidelines require the Funding Report to be filed. See DEC – Maness Cross-Examination Ex. 1, Tab 1, Attachment 1.

[42] Witness Hinton's direct testimony indicated that this figure was $19.4 million (Tr. Vol. 22, p. 252), but he discovered an error in his analysis and corrected the figure to $29.1 million Id. at 260.

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accurate through when DEC's last nuclear unit is decommissioned, the NDTF is currently over-funded by $2.35 billion." Tr. Vol. 22, p. 252 (emphasis added). A number of qualifiers and the uncertainty regarding future events underlie witness Hinton's conclusion that the NDTF is currently overfunded. Id. However, witness De May testified that on an NC retail basis, the NDTF is actually underfunded as of the end of the test year:

> [T]he NDTF balance was $2.19 billion as of December 31, 2016. The estimated decommissioning cost (in 2016 dollars) as of December 31, 2016 was $2.46 billion. In other words, on a current dollars basis, the NDTF was approximately 89% funded as of December 31, 2016.

Tr. Vol. 4, pp. 79-80.

Witness De May further testified that the Company uses three methods to determine whether the funding levels in the NDTF are adequate such that the nuclear decommissioning portion of cost of service should be assigned a zero-dollar cost. One is the "current value" method, which is what is described above. Another is the "projected value" method, which is the basis of witness Hinton's conclusion. The projected value method measures, as its name suggests, the funds in the NDTF projected as of the end of decommissioning, still decades into the future, compared to projected costs, again decades into the future. In other words, the projected value method measures "the projected balance of the NDTF at the end of the decommissioning period, i.e., after all decommissioning activities are completed, and is in future dollars (ranging from 2058 through 2067)." Id. (emphasis added). Witness De May testified that this measure indicates whether the NDTF is adequately funded, but does not indicate that it is fully funded – for that, one cannot know "until the last dollar is spent on decommissioning." Id. at 568.

The third method witness De May described is the "probability of success" method. This method, witness De May explained, uses a probability of success ratio to evaluate the likelihood of having sufficient funds to fully decommission each nuclear unit. Id. at 80. This approach involves 5,000 Monte Carlo simulations of market returns and escalation factors between the time of analysis and the end of decommissioning and generates a percentage of scenarios for which funding is adequate to meet all future decommissioning obligations. Id. Witness De May testified that "[a]s of December 31, 2016, the nuclear unit probability of success ratios ranged from 77% to 85%, depending on the unit; conversely, the probability of not having sufficient funds to decommission the nuclear units ranged from 15% to 23%." Id. (emphasis in original). Although these percentages may support a determination that no additional funding from ratepayers is currently required to fund the NDTF, the Company submits that in no way should this be interpreted as supporting a view that the NDTF is "overfunded."

The Company based its determination that the NDTF funding levels were adequate and that, as a consequence, it would not request any nuclear decommissioning cost in its revenue requirements in this case, on the fact that the NDTF has experienced higher than expected returns recently and that the escalation rate assumption has remained modest. Id. at 82. There is, of course, no assurance that these conditions will extend into the future, and certainly no assurance that they will extend decades into the future. Uncertainty is further

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compounded by timing, as license extensions or unforeseen circumstances could accelerate or push out the plants' retirement dates. Insofar as escalation rates are concerned, witness De May testified that the model used to estimate funding requirements is highly sensitive to changes in the escalation rate assumption, and that an "increase in the forecasted escalation rate from 2.40% to 3.09%, a 0.69% increase, fully eliminates the projected NDTF overfunded balance at the end of the decommissioning period." Id. He noted that for the period 1913-2017, the average consumer price index (CPI-U) rate has been 3.24%. Accordingly, changing the escalation rate from the currently model rate of 2.4% just to the average CPI-U increase over the past hundred years means that the Public Staff's projected $2.35 billion overfunding disappears. Id. at 587.

He also testified regarding returns, "You probably hear this all the time in investment jargon, past returns are not an indication of future results." Tr. Vol. 5, p. 58. A 2015 Public Staff Report (DEC – Maness Cross-Examination Ex. 2), noted:

> The current healthy financial position of the … [NDTF] relative to estimated costs results largely from significantly higher than expected trust fund investment returns that have been experienced in recent years. The trust fund has not, however, always experienced such strong investment returns, and in fact, there have been many years of low or negative investment returns.

Id. at 13.[43]

Witness Hinton attempts to address concerns that the Public Staff's recommendation would lead to future underfunding by asserting that there are sufficient regulatory protections to avoid any significant under recovery in the NDTF. Tr. Vol. 22, p. 252. However, DEC contends that this statement ignores that some of those protections include restrictions preventing withdrawals from the NDTF. As witness De May indicated,

> [T]here is a reason it's illegal to take money out of the trust. It's because … [the NDTF is] not an investment account, it's not a savings account. It's there for the very good public policy of decommissioning nuclear power plants ….

Tr. Vol. 4, p. 588.

In light of all of the evidence presented, the Commission determines that it is premature to find and conclude that the NDTF is overfunded. While the funding model that is used to determine the annual nuclear decommissioning expense forecasts that under various assumptions, the NDTF may be overfunded by approximately $2.4 billion,

[43] For example, industry-wide from 2006 through 2008, the financial markets had a significant negative impact on trust fund balances. See NRC Office of Nuclear Regulation, 2009 Summary of Decommissioning Funding Status Reports for Nuclear Power Reactors (SECY-09-0146, October 6, 2009), p. 7, available online at: https://www.nrc.gov/docs/ML0925/ML092580041.pdf. The Commission takes judicial notice of this NRC report.

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the evidence also indicates that on a current dollar basis it is only 89% funded. The Commission agrees with witness De May's concern that returning the projected excess funds to ratepayers now could lead to underfunding of the NDTF in the future. The record shows that the NDTF has experienced higher than expected returns recently, and the escalation rate used to forecast decommissioning costs has remained modest compared to historical rates of inflation, both of which have contributed to favorable results. Changes in assumptions for variables, including investment returns, escalation rates and decommissioning start or completion dates, will all impact future NDTF funding levels, as will deviation of future experience from current forecasts. In the judgment of the Commission, while the NDTF is currently adequately funded, it is premature to find and conclude that the NDTF is overfunded, and therefore, it would not be prudent to return funds to customers at this time, and perhaps for several years, even if it were legally permissible to do so.

Given the Commission's finding and conclusion in this regard, it is not necessary for the Commission to address the related issues between the parties regarding GAAP treatment, retroactive ratemaking and prior agreements.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 52-55

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of DEC witnesses Spanos, Doss, and Kopp, Public Staff witness McCullar, and the entire record in this proceeding.

Company witness Doss introduced Doss Exhibit 3, the revised depreciation study filed in this docket (Depreciation Study), as prepared by Gannett Fleming Valuation and Rate Consultants, LLC. Tr. Vol. 12, p. 56. As explained by witness Doss, the Depreciation Study included updates to estimates of final plant depreciation costs for steam, hydraulic, and other production plants, as well as updated forecasted generation plant retirement dates. Id. at 77. In addition, witness Doss introduced Doss Exhibit 4, the Decommissioning Cost Estimate Study (Decommissioning Study) prepared by Burns and McDonnell Engineering Company, Inc. (Burns & McDonnell), an external engineering firm. This report included estimates for final decommissioning costs at steam, hydraulic, and other production plants.

DEC witness Doss testified that the updated depreciation rates for various fossil and hydro plants reflect changes in the probable retirement dates to align with current licenses, industry standards, or operational plans due to aging technology, assumptions for future environmental regulations, or new planned generation. Tr. Vol. 12, pp. 51-52. In addition, the Depreciation Study incorporates generation assets that have been placed in service since the last study, as well as the W.S. Lee Combined Cycle Plant, once it goes into service. Id. at 52. Additionally, the rate for meters to be replaced under the Company's Advanced Metering Infrastructure (AMI) deployment was updated to allow recovery of the net book value over three years. Id. The Depreciation Study uses a 15-year average service life for the new AMI meters being deployed, increasing depreciation expense. Id. Finally, witness Doss also notes that there is a net decrease in

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the depreciation expense for distribution, transmission, and general plant assets, primarily driven by longer average service lives for assets such as overhead and underground conductors and services. Id.

Public Staff witness McCullar and CIGFUR III witness Phillips also made recommendations related to depreciation expense. Witness McCullar recommended several adjustments to the Company's proposed depreciation rates including adjustments to future terminal net salvage costs (also known as decommissioning and dismantlement costs), to other production plant interim net salvage percentages, and to remove inflation from terminal net salvage costs. Tr. Vol. 26, pp. 777-78, 783-85. Witness McCullar testified that based on December 31, 2016 investments, DEC was proposing an increase in its depreciation annual accrual of $81,480,296. Tr. Vol. 26 p. 773. Based on Public Staff witness McCullar's investigation, the Public Staff recommended an increase in DEC's depreciation annual accrual of $20,709,566 based on December 31, 2016, investments, a decrease of $60,770,730 from the amount proposed by the Company. Tr. Vol. 26, p. 775. The difference between the Company's and the Public Staff's proposed depreciation annual accrual results from four adjustments proposed by witness McCullar, and one recommended by Public Staff witness Maness, as discussed below. Finally, witness Phillips recommended that changes in the depreciation rates should net to a zero-dollar impact.

Estimated Terminal Net Salvage Costs – Contingency

Burns & McDonnell conducted the Decommissioning Study for DEC, which formed the basis for DEC's terminal net salvage cost estimates. In that study, a 20% contingency for future "unknowns" was included in DEC's estimate of future terminal net salvage costs. "Public Staff witness McCullar recommended that the 20% contingency for future "unknowns" included in DEC's estimate of future terminal net salvage costs be eliminated. Tr. Vol. 26, p 778. Witness McCullar explained that including a 20% contingency factor puts the risk of possible future unknowns on current ratepayers. Id. Witness McCullar pointed out that DEC has not identified actual future costs to be covered by the contingency, but estimates future terminal net salvage costs based on anticipated contractors' bids for dismantlement of equipment, addressing of environmental issues, and restoration of the site, and then adds 20% for unknown costs that DEC cannot specifically identify. Tr. Vol. 26, pp. 778-79. Public Staff witness McCullar testified that putting all the risk of "estimated future unknown unidentified costs" on current ratepayers was inappropriate and recommended a contingency of 0%. Tr. Vol. 26, p. 780. In response to witness McCullar's recommendation, DEC witness Kopp explained why a 20% contingency is appropriately included in DEC's Decommissioning Study. He explained that contingency protects customers by ensuring more accurate estimates of the costs of terminal net salvage to be incurred in the future. Tr. Vol. 10, p. 108. He stated that while these costs could not be specifically identified, it was reasonable to expect them to be incurred. Id. Witness Kopp explained that direct decommissioning costs were estimated based on performing known tasks under ideal conditions. Tr. Vol. 10, p. 109. However, Company witness Kopp admitted that Burns & McDonnell did not obtain any firm quotes for DEC facilities, but used unit pricing or its experience. Tr. Vol. 10, p. 137.

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Further, according to witness Kopp, the contingency was added to recognize the likelihood of cost increases for unknown costs. Id. He pointed out uncertainties in work conditions, scope of work, the manner in which work would be performed, estimating quantities, weather, and unknown contamination, among other things. Tr. Vol. 10, pp. 109-10. DEC witness Kopp testified that inclusion of contingency costs was standard industry practice. Tr. Vol. 10, p. 110. He explained that a 20% contingency was appropriate at a site where power had been generated for years and where there was likely to be more environmental contamination, and thus was based on the level of risk of additional contamination. Tr. Vol. 10, pp. 111-12. Witness Kopp pointed out that there had been no on-site testing for hazardous materials or environmental contamination, no sampling of groundwater, no subsurface investigation, no asbestos inventories, and that the cost estimates included only a minimal level of environmental remediation. Tr. Vol. 10, pp. 111-12. Company witness Kopp contended that it would not be prudent to try to develop estimates that were more accurate or precise so that a smaller contingency would be reasonable, because of the high cost of conducting such a study and the limited time that the cost estimates could be considered reliable. Tr. Vol. 10, p. 113. Yet he argued that while these estimates were not precise enough to develop a more reasonable contingency, they were precise enough on which to base depreciation rates. Tr. Vol. 10, pp. 113-14. DEC witness Kopp noted that Burns and McDonnell had performed a decommissioning study for DEP in 2012, and that study's estimates for the decommissioning and demolition of Cape Fear, H.F. Lee, Sutton, Robinson, and Weatherspoon plants forecast costs 11% lower than actually incurred. Tr. Vol. 10, p. 114.

Accordingly, witness Kopp explained that a 20% contingency on these costs is both reasonable and warranted based on the risk level associated with the decommissioning projects. As the Company pointed out in its Response to Public Staff Data Request No. 17, the anticipated contractor's bid is based on performing known dismantlement tasks under ideal conditions. Id. at 116. (emphasis added) Witness Kopp contended that Public Staff witness McCullar had not taken into account that the direct costs were based on known tasks occurring under ideal conditions. Tr. Vol. 10, pp. 115-16. Witness Kopp also pointed out the minimal level of investigation Burns & McDonnell made into the existence and costs of potential environmental contamination and remediation, which he argued supported a 20% contingency. Tr. Vol. 10, p. 116. Regarding witness McCullar's contention that the Company should not recover a contingency for costs that cannot be identified at this time, witness Kopp agreed that specific future costs could not be identified, but noted that some typical costs that might be incurred or that have been incurred on similar projects were known. Tr. Vol. 10, pp. 117-18.

On cross examination, Company witness Kopp indicated that the Decommissioning Study did not take into account the impact of any planned changes to convert the Belews Creek, James E. Rogers (Cliffside), and Marshall plants to dual fuel capability as planned by the Company (Spanos/Kopp Cross Exhibit 1), which could increase or decrease the study's estimates. Tr. Vol. 10, pp. 127-29. Neither did the study take into account any changes in steel and aluminum prices that might occur due to imposition of tariffs. Tr. Vol. 10 pp. 133-34. Witness Kopp also stated that

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decommissioning and demolition was the most prudent option at the end of a plant's useful life, but acknowledged sale of a plant as another option. See Duke Energy's announcement of the sale of its retired Walter C. Beckjord coal-fired power plant, Spanos/Kopp Public Staff Cross Exhibit 3. Tr. Vol. 10, pp. 131-33.

In his testimony, DEC witness Kopp testified that, "[a]s engineering design for demolition progresses and some of these unknowns can be determined through subsurface investigations, asbestos sampling, and engineering specifications, the amount of contingency may be reduced; however, contingency would never be completely eliminated." Tr. Vol. 10, pp. 112-13. He also stated that the "Company performed no subsurface investigations, asbestos inventories, or groundwater sampling to identify and define remediation requirements during this planning phase." Tr. Vol. 10, p. 112. However, on cross-examination, witness Kopp admitted that the Company did perform asbestos inventories. Tr. Vol. 10, p. 136. But instead of relying on studies that had been performed, "Burns and McDonnell did not rely upon these historical studies ...." Tr. Vol. 10, p. 136.

DEC witness Kopp highlighted all the environmental testing that has yet to be done and all the uncertainties inherent in the study. While the Decommissioning Study was conducted based on data from 2016 and 2017, DEC has since announced plans to convert three of its plants to dual-fuel capability, changing some of the assumptions in the study. While it is impossible to anticipate all future costs, merely being able to identify possible future costs or costs incurred for other projects is not the most firm basis on which to calculate contingency. This causes some concern for the Commission.

The Commission takes note that the Company failed to take into account the possibility that scrap prices may increase or that the production plant may be repurposed, or sold. Further, DEC witness Kopp's claim that a contingency is needed to account for the unknown of asbestos is not fully supported by the record in this proceeding, since DEC has performed asbestos inventories and identified an asset retirement obligation for these legal asbestos abatement obligations. See Kopp/Spanos Public Staff Exhibit 4. Identifying these costs should reduce the unknown of asbestos and thus reduce any contingency.

Based on the above discussion and all of the evidence in the record, the Commission finds that the contingency proposed for net terminal salvage in this proceeding of 20% is improper and should be reduced. While the Commission appreciates the Public Staff's concern for keeping depreciation rates low, the potential for further environmental costs and remediation costs should not be given short shrift, especially in light of other environmental costs that are discussed elsewhere in this Order. However, the Commission acknowledges the arguments that the Public Staff has made, and in an attempt to strike a fair balance, the Commission finds that a 10% contingency factor is fair to all parties. The Commission further notes that in DEP's most recent rate case proceeding, Docket No. E-2, Sub 1142, the Commission approved a 10% contingency factor. The Commission is confident that a 10% contingency factor, while less than DEC's requested factor of 20%, should protect the Company from additional

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costs it will incur but cannot specify at the present date. The Commission also finds that a 10% contingency factor properly reflects the inclusion of items that should push unknown costs downward (i.e increase in scrap prices, etc.) thereby protecting the ratepayers as well. Based on the foregoing, the Commission concludes that including a contingency factor of 10% should be utilized by the Company.

Cost Escalated to the Date of Retirement

It is important to recover the service value of the Company's assets by determining the net salvage costs that will be incurred in the future. As DEC witness Spanos explained, using the straight-line method of depreciation, these costs are recovered ratably, or in equal amounts, each year over the life of the Company's plant. Tr. Vol. 10, p. 83. This approach is consistent with the Uniform System of Accounts, which specifies that the cost of removal is the actual amount paid at the time the transaction takes place. Id. at 84. As such, including the future cost of net salvage for plant accounts is consistent with established depreciation concepts. In developing decommissioning cost estimates, it is necessary to escalate those estimates to the time period in which the cost is expected to be incurred.

Public Staff witness McCullar testified that the Company took the estimated future terminal net salvage costs from the Decommissioning Study, which are in year 2016 dollars, and inflated them to the year of the assumed retirement of the production plant. She testified that DEC proposes to collect these inflated amounts in today's more valuable dollars from ratepayers. Tr. Vol. 26, pp. 780-81. Witness McCullar's Exhibit RMM-2 showed how for the Cliffside plant, the estimated terminal net salvage cost of $48,075,000 in year-2016 dollars was inflated to $105,945,645 in year-2048 dollars, assuming an annual inflation rate of 2.5% to 2048, the estimated year of retirement, increasing the estimated net salvage cost by a factor of 2.2. Tr. Vol. 26, p. 781. DEC proposes to begin collecting this $105,945,615 calculated using year-2048 dollars from current ratepayers, who would be paying in current dollars. Id. Public Staff McCullar contended that it would be unreasonable in this case to collect these inflated costs of removal in current dollars because it imposes too much risk on ratepayers due to the significant period of time over which the inflation is estimated. Tr. Vol. 26, p. 282.

Witness McCullar recommended that DEC should inflate the terminal net salvage costs to the year 2023, or the retirement date, whichever occurs first. Witness McCullar testified that she selected 2023 because it aligned with the time when the Company is expected to file its next rate case. Witness McCullar stated, "since depreciation rates approved in this proceeding are expected to go into effect in 2018, the year 2023 would be five years later, by which time depreciation rates would have been reviewed in a new base rate case." Tr. Vol. 26, p. 784. Witness McCullar noted that her recommendation reduces the risk on ratepayers associated with paying rates based on extended periods of estimated inflation, while protecting the Company from the risk that it would not be able to collect its net salvage costs. Tr. Vol. 26, p. 784.

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Witness Spanos explained that many of the Company's plants will not be retired for many years. Tr. Vol. 10, p. 86. Witness Spanos highlighted the importance of "understanding the Company's expectations for these assets, as well as the estimates within the industry." Id. at 91. Accordingly, the net salvage costs must be escalated so that the correct amounts are allocated over the remaining lives of the plants. Tr. Vol. 10, p. 86. The approach used by the Company to escalate cost is widely supported by authoritative depreciation texts and industry practice. For example, witness Spanos pointed out that the NARUC Manual provides the following:

> Under presently accepted concepts, the amount of depreciation to be accrued over the life of an asset is its original cost less net salvage. Net salvage is the difference between gross salvage that will be realized when the asset is disposed of and the costs of retiring it.

Tr. Vol. 10, p. 88. (emphasis added).

In addition, Wolf and Fitch, another highly regarded authoritative depreciation text, provides further support for the position that inflation is appropriately a part of the future cost of net salvage. Wolf and Fitch also argue against a present value or current value concept. In his testimony, Witness Spanos provided the following passage from Wolf and Fitch:

> Some say that although the current consumers should pay for future costs, the future value of the payments, calculated at some reasonable interest rate, should equal the retirement cost. Studies show that the salvage is often "more negative" than forecasters had predicted.

Tr. Vol. 10, p. 89.

Finally, witness Spanos referenced Accounting for Public Utilities by Robert L. Hahne and Gregory E. Aliff to support the proposition that the Uniform System of Accounts and regulatory definition require net salvage to be estimated at a future price level. Id.

The testimony and evidence presented in this case demonstrates that authoritative texts and sound depreciation practices support escalating terminal net salvage costs to the date that the costs are expected to be incurred. Despite arguing against an approach in which the Company would recover costs over the life of the asset, witness McCullar concedes that some escalation is necessary. In fact, witness McCullar escalated terminal net salvage to the projected date for the Company's next base rate case in her calculations. Further, witness McCullar's escalation rate is entirely dependent on the timing of when the Company files its base rate case and lacks any nexus to the timing of the future retirement of the asset. The Commission notes that the record is void of any accounting literature support for witness McCullar's approach, nor would such an approach be appropriate.

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The Commission cannot rely upon the scheduling of rate cases to remedy the flaws in witness McCullar's alternative proposal. Witness McCullar's approach is not supported by sound depreciation methods and would likely result in the under recovery of net salvage costs over the life of the asset. To that end, other state utility commissions have rejected witness McCullar's alternative approach as unsupported. For example, in a recent case before the Washington Utilities and Transportation Commission (WTC), witness McCullar advanced similar arguments against the escalation of terminal net salvage costs along with other recommendation related to depreciation.[44] In rejecting the recommendation, the WTC noted that Public Counsel and witness McCullar provided no response to the critique that witness McCullar's approaches were not supported by authoritative accounting literature.[45] The WTC found witness McCullar's net salvage proposal "[v]ague in its methodology, not supported by authoritative accounting literature, and supported by unwarranted assumptions."[46]

The fact is the vast majority of jurisdictions use a method for net salvage in which future net salvage is estimated at its future cost and recovered through straight-line depreciation (also known as the traditional method). Approximately 46 out of 50 jurisdictions recover future costs using the straight-line depreciation method. The use of this method is also consistent with the treatment of escalation in the most recent DEP rate case. As witness Spanos explained, depreciation should be done in a systematic and rational manner based on information known at the time and consistent with the Uniform System of Accounts. Id. at 165.

Considering all the evidence, the Commission finds and concludes that the escalation of terminal net salvage cost and the use of the straight-line method of depreciation in determining escalation as performed in the DEC Decommissioning Study is just and reasonable, appropriate for use in this case, and is adopted.

Other Production Plant Interim Net Salvage Percent Production Accounts

In this case, DEC witness Spanos testified that he recommended a future net salvage percent of negative 4% for other production accounts. Id. at 90. The estimated future net salvage is part of the annual depreciation accrual, which is credited to the reserve to cover the estimated future net salvage costs. As witness Spanos explained, he established an interim net salvage percent on an account basis and then performed the appropriate calculation in order to get the appropriate weighted interim net salvage, excluding account 343.1. Tr. Vol. 12, p. 143. The net salvage estimates were based on

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[44] See Washington Utilities and Transportation Commission v. Puget Sound Energy, Final Order Rejecting Tariff Sheet; Approving and Adopting Settlement Stipulation; Resolving Contested Issues, & Authorizing and Requiring Compliance Filing, Washington Utilities & Transportation Commission, Docket UE-170033 (December 5, 2017) Puget Sound Order.

[45] Puget Sound Order, pp. 50-51.

[46] Id. at 60. The WTC noted further that witness McCullar's "comparison of net salvage accruals to net salvage expenditures PSE incurred during recent years would effectively recover net salvage as an operating expense, not a depreciation expense."

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an analysis of historical cost of removal and salvage data, expectations with respect to future removal requirements, and markets for retired equipment and materials. See Doss Exhibit 3 IV-2; Tr. Vol. 12, p. 116. The interim net salvage component is approximately 32% of the utilized net salvage percent for other production plant. Id. at 90. Witness Spanos further testified that he noted that the Public Staff's recommended interim net salvage percentage had been included in the depreciation rate proposed for the Lee Combined Cycle Plant. Id. DEC witness Spanos contended that determining an interim net salvage percentage for other production plant should be based on historical data as well as informed judgment. Id. He stated that Accounts 343 and 344 included large amounts of gross salvage related to older combined cycle facilities not applicable to all assets in the account. Id. Company witness Spanos also stated that the high gross salvage numbers were related to the rotable parts of combined cycle facilities, consistent with DEP. Id.

Public Staff witness McCullar proposed a 0% net salvage value for accounts 342, 343, 344, 345, and 346. She testified that for some accounts, the annual accrual amount that would be accrued for estimated net salvage is several times the annual amount DEC actually incurs for net salvage. Tr. Vol. 26, p. 278. Witness McCullar indicated that the historical analysis has been a positive $12,891,310 per year for the last three years and a positive $8,649,160 per year for the last five years. Witness McCullar explained that these positive net salvage amounts indicated that DEC's booked gross salvage exceeded the Company's incurred costs of removal and thus, DEC did not need to collect interim removal costs for these accounts. As a result, witness McCullar took the position that DEC should utilized a 0% interim net salvage based on DEC's actual experience. Witness McCullar further testified that the 0% interim net salvage would not include the final decommissioning costs. The impact of the Public Staff's proposed adjustments to terminal net salvage contingency and escalation rates and interim net salvage results in a decrease in DEC's proposed depreciation rates as of December 31, 2016, of $13,382,159, as shown on p 14 of Exhibit RMM-1 on the line for Total Production. Tr. Vol. 26, p. 786.

In response, witness Spanos testified that in the case of other production plant, it is critical to understand all the components of the historical data. For example, in Accounts 343 and 344, there are large amounts of gross salvage and corresponding retirements that relate to the early installations of combined cycle facilities which are not applicable to all assets in the account. Tr. Vol. 10, p. 91. As witness Spanos described further, the high gross salvage amounts relate to the rotable parts of the combined cycle facilities, which are handled consistently with DEP's assets. Id. Under cross-examination by Public Staff, witness Spanos explained that Account 343 contains high salvage amounts in years 2014, 2015, and 2016, but using informed judgment, he understood those amounts to be related primarily to rotable parts and associated with combined cycle facilities. Using more than just statistical analysis is necessary to evaluate these production plants; informed judgment must also be relied upon as Witness Spanos did. In recommending the negative 4% interim net salvage percentage, witness Spanos took into account the Company's expectations for the assets as well as the estimates within the industry. Id.

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The Public Staff presented evidence on cross-examination of DEC witnesses Kopp/Spanos regarding the Company's proposed positive net salvage percentages in Accounts 343 and 344 were related to rotable parts. Kopp/Spanos Public Staff Cross-Examination Exhibit 7 shows that DEC has established rotable parts in a separate account, Account 343.1. Further, Kopp/Spanos Public Staff Cross Exhibit 8 shows that the Public Staff did not propose any adjustment to the interim net salvage percentage for Account 343.1, Prime Movers Rotable. Additionally, under cross examination, witness Spanos admitted that Account 343.1, containing these rotable parts, was also excluded from the Company's interim net salvage proposal for Accounts 342, 343, 344, 345, and 346. Tr. Vol. 10, p. 143.

Based on the evidence discussed above and the entire record in this case, the Commission finds that the Public Staff's proposal to set an interim net salvage percentage of 0 for Accounts 342, 343, 344, 345, and 346 is reasonable. Historical data show that using a negative value, as was previously set, has resulted in DEC overcollecting its costs. It would be inequitable to charge customers for costs that the utility is unlikely to incur. As discussed previously, the Company has stated publicly that it plans to file multiple rate cases between 2019 and 2023, and therefore, this issue can be reexamined in the next base rate case.

Other Depreciation Recommendations

CIGFUR III witness Phillips recommended that any approved changes to depreciation rates should net to a zero-dollar impact on the level of depreciation expense included in rates. Tr. Vol. 10, p. 94. He further recommended that customers not be burdened at this time by the impact of shortening service lives of generating plants based upon assumptions about changing and evolving environmental regulations. Id.

As DEC witness Spanos correctly asserted, witness Phillips provided no support or justification for his net zero proposal, other than a desire that depreciation rates not increase. Tr. Vol. 10, p. 94. Witness Phillips offered no credible critique of the Company's filed Depreciation Study and provided no alternative analysis. The Depreciation Study demonstrates that current depreciation rates are insufficient and that adjustments are necessary for DEC to recover the full cost of its assets providing service to DEC's customers. Id. at 95.

Furthermore, witness Phillips incorrectly states that depreciation rates have changed due to changes to life spans as a result of environmental regulation. Witness Spanos highlighted that there are a variety of reasons that depreciation rates change over time as evidenced by the Depreciation Study filed in this case. The Depreciation Study includes all of DEC's assets, and changes in depreciation rates occur for many reasons, including updated service life and net salvage estimates, updated historical data, and additions to generating facilities. The Depreciation Study is based upon the available information regarding the Company's assets, and the depreciation rates, therefore, needs to be updated to reflect current circumstances. Tr. Vol. 10, p. 95.

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For the foregoing reasons, CIGFUR III witness Phillips' blanket recommendation regarding depreciation rates lacks any conclusive support and is rejected.

Conclusion

In light of all of the evidence presented, the Commission finds and concludes that the depreciation rates proposed by DEC in this case, which are based on the revised Depreciation Study included as Doss Exhibit 3 and the Decommissioning Study included as Doss Exhibit 4, with the exception of the adjustments discussed above, are just and reasonable, fair to both the Company and its customers, and therefore, are approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 56-58

The evidence in support of these findings of fact and conclusions is contained in the testimony and exhibits of Company witnesses De May, Fountain, and McManeus; Public Staff witnesses Boswell, Parcell, and Hinton; Tech Customers witnesses Strunk and Brown-Hruska, NCLM witness Coughlan; Justice Center et al. witness Howat; Kroger witness Higgins; CIGFUR III witness Phillips and the entire record in this proceeding.

The federal Tax Cuts and Jobs Act (the Tax Act) was signed into law on December 22, 2017. Among other provisions, the Tax Act reduced the federal corporate income tax rate from 35% to 21%, effective January 1, 2018.[47] It also repealed the manufacturing tax deduction and eliminated bonus depreciation. The Company filed its application for rate increase on August 25, 2017, many months before the enactment of the Tax Act and, therefore, the revenue requirement the Company requested was based on the pre-Tax Act tax laws.

On January 16, 2018, DEC witness McManeus filed her Second Supplemental Direct Testimony that only included limited discrete changes as a result of the Tax Act relating to the elimination of bonus depreciation and the manufacturing tax deduction. Her filing did not include an adjustment to income tax expense as a result of the decrease in the federal corporate income tax rate, nor did it include any proposal for the return of the protected and unprotected Federal EDIT to ratepayers.

In her direct testimony filed on January 23, 2018, Public Staff witness Boswell included an adjustment to income tax expense to reflect the decrease in the federal corporate income tax rate, as well as to remove the manufacturing tax deduction that was also included in the Tax Act. She stated that at that time, the Public Staff was waiting for information from the Company regarding Federal EDIT and reserved the right to supplement her filing to include the Public Staff's proposal for flow back of Federal EDIT.

[47] In response to the enactment of the Tax Act, on January 3, 2018, the Commission opened a rulemaking docket (Docket No. M-100, Sub 148, i.e. the Tax Docket) for the purpose of determining how the Commission should proceed. In the Order establishing the Tax Docket, the Commission placed all public utilities on notice that the federal corporate income tax expense component of all existing rates and charges, effective January 1, 2018, would be billed and collected on a provisional rate basis.

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In rebuttal testimony filed on February 6, 2018, DEC proposed an immediate reduction in the Company's revenue requirement, within the context of this proceeding, to account for the reduction in the federal corporate income tax rate but offered no proposal to return Federal EDIT to ratepayers. Company witness Fountain testified that the passage of the Tax Act "provides the Commission with a unique tool to smooth out customer rate adjustments during a multi-year transition period." Tr. Vol. 6, p. 212. He stated that this could be accomplished by offsetting items such as storm response costs, ongoing coal ash basin closure compliance costs or other environmental compliance costs, or accelerating the depreciation of certain assets, such as the existing AMR meters or coal plants. Tr. Vol. 6, p. 213.

In her rebuttal testimony, witness McManeus testified that the Company opposed witness Boswell's adjustment to reduce income tax expense. Tr. Vol. 6, p 323. Witness McManeus testified that the Company had identified the amount of reduction in annual revenue requirement related to reduced income tax expense and translated the amount into a decrement rate per kWh. Witness McManeus stated that the Company proposed to apply the decrement to North Carolina retail service beginning January 1, 2018, and defer the resulting amount into a regulatory liability, continuing the deferral until new rates are established in this rate case that reflect the benefits of the lower tax expense. Tr. Vol. 6, p. 331.

In supplemental testimony filed on February 20, 2018, witness Boswell presented the Public Staff's proposal regarding the flowback of Federal EDIT. Witness Boswell included three adjustments based on the information provided by the Company. First, she recommended the return of protected Federal EDIT based upon the Company's calculation of the net remaining life of the timing differences, as required under the Internal Revenue Code. For the unprotected Federal EDIT, witness Boswell recommended removing the Federal EDIT regulatory liability associated with the unprotected differences from rate base, and placing it in a rider to be refunded to ratepayers over two years on a levelized basis, with carrying costs. Witness Boswell stated that immediate removal of unprotected Federal EDIT from rate base increases the Company's rate base and mitigates regulatory lag that might occur from refunds of unprotected Federal EDIT not contemporaneously reflected in rate base. Further, she maintained that refunding the unprotected Federal EDIT over two years allows the Company to properly plan for any future credit needs. Tr. Vol. 26, pp. 618-19. Ultimately, during the hearing, the Public Staff modified its proposal to adjust the flowback period from two years to five years. Boswell Second Supplemental Testimony, filed March 19, 2018, Tr. Vol. 26, pp. 637-38. The modified proposal is referred to herein as the Public Staff Proposal.

In response to the Public Staff's original 2-year EDIT flowback proposal, the Company Proposal was made initially in Supplemental Comments, filed March 1, 2018, in Docket No. M-100, Sub 148, a docket that the Commission established on January 3, 2018, in order to gather comments from the utilities it regulates along with the Public Staff and other interested parties, to decide how to implement the Tax Act (Tax Docket). By letter filed the next day, the Public Staff objected to the Company Proposal being made

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in the Tax Docket, in light of the fact that the Company's general rate case was then open and had not yet gone to hearing. Accordingly, the Company then made its proposal in this Docket on the opening day of the expert witness evidentiary hearings, and the Commission took judicial notice of all filings in the Tax Docket. Tr. Vol. 5, p. 14.

On the first day of the evidentiary hearing, the Company presented its proposal to address the Tax Act. The Company Proposal was presented in this proceeding by witness De May. Tr. Vol. 4, pp. 423-24; Tr. Vol. 5, pp. 67-79; De May Rebuttal Ex. 5. The Company Proposal has three basic component parts, and the first two components reduce the Company's revenue requirement.

First, the Company Proposal implements an immediate reduction of approximately $211.5 million to the Company's revenue requirement to reflect collection of federal corporate income tax at the 21% rate instead of the 35% rate. Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues, Line 29; Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Line 1.

Second, the Company Proposal implements Federal EDIT flowback to customers, with the flowback timeframes varying based on the particular Federal EDIT bucket at issue:

- For protected Federal EDIT, the Company Proposal applies the Tax Act-prescribed IRS normalization rules, resulting in a reduction in revenue requirements of approximately $34.4 million annually or per year. Revised McManeus Stipulation Ex. 1 – Updated for Post-Hearing Issues, Line 30; Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Line 2.
- For unprotected Federal EDIT related to property, plant and equipment, the Proposal also applies the normalization rules, although, as all of the parties agree, application of those rules is not required by the Internal Revenue Code. The only modification, that results in a faster flowback, is that while the Company's analysis indicates that the average life of the flowback in the absence of the Tax Act would have been 25 years, the Proposal implements that flowback over 20 years. Tr. Vol. 5, pp. 78, 105. DEC maintained that this was done "for the sake of simplicity" (id. at 105.), and results in a reduction in revenue requirements of approximately $36.7 million annually or per year. Revised McManeus Stipulation Ex. 1 – Updated for Post-Hearing Issues, Line 33; Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Line 3.
- For unprotected Federal EDIT not related to property, plant and equipment, the Proposal implements flow back through a five-year decrement rider, with the five-year timeframe being used again "for the sake of simplicity." Tr. Vol. 5, p. 105. The reduction in revenue is approximately $39.6 million per year during the five years the rider is in effect. Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Line 7. Because these unprotected Federal EDIT are being flowed back to customers through a rider, that includes a return component, base rates must be adjusted correspondingly (as an increase) in the

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amount of $15.1 million. Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Line 5.

Accordingly, the reduction in revenue requirements effected by these two components of the Company Proposal equals $307.1 million annually or per year. Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Lines 1-3, 5 and 7.

The third component of the Company Proposal mitigates, but does not eliminate, the negative cash flow impact of these reductions by increasing annual revenue requirements by $200 million. The Company Proposal (De May Rebuttal Ex. 5) did not originally identify specific means through which this could be accomplished, but did provide examples of accelerated regulatory asset amortization, and also suggested the alternative of collecting certain expenses (for example, the coal ash basin closure cost "run rate") on an accelerated basis.[48] As witness De May testified, in concept this component of the Company Proposal aims "to preserve the cash flow and credit quality, and we can skin that cat a few ways." Tr. Vol. 5, p. 87.

Combined, therefore, the three component parts of the Company Proposal net to a reduction in the Company's annual revenue requirement of almost $107 million. Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1. The Company Proposal implements an immediate reduction in rates to reflect the 21% Federal corporate income tax rate, but also, as witness De May testified, mitigates the impacts and "preserve[s] … [the Company's] credit quality ... to something that resembles pre-tax reform." Tr. Vol. 5, p. 82.

On cross-examination, Company witnesses Fountain and McManeus were questioned about the Company's income tax proposal. Witness McManeus acknowledged that ratepayers advanced the funds that constitute the Federal EDIT at issue. Tr. Vol. 6, p. 399. She also conceded that tax normalization laws do not dictate when unprotected PP&E Federal EDIT should be returned to ratepayers (unlike protected Federal EDIT). Tr. Vol. 6, p. 399. Witness McManeus further admitted that because unprotected Federal EDIT is not subject to tax normalization rules, the Commission has discretion as to the time period over which the funds will be returned to ratepayers. Tr. Vol. 8, p. 224. She agreed that due to the reduction in the tax rate, the Federal EDIT is no longer needed to cover the Company's taxes. Tr. Vol. 8, p. 224. Witness McManeus acknowledged that the $200 million in accelerated expenses would be included in the Company's revenue requirement. Tr. Vol. 8, p. 226. When asked to identify the specific assets and other items that the Company would include in the proposed $200 million acceleration, she could not identify anything specific, referring to the general options set forth in the proposal. Tr. Vol. 8, p. 230. Witness Fountain conceded that he could understand the positon of some customers who would like to have the benefits of the

[48] Kathy Sparrow, one of the public witnesses in the public witness hearing held in Charlotte on January 30, 2018, also suggested that tax reform gains and coal ash costs could offset against each other. Tr. Vol. 3, p. 95.

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federal tax reform all flowed back immediately, but testified that the Company's proposal is balanced. Tr. Vol. 7, p. 94.

In response to Commission questions about the Company's income tax proposal, witness McManeus testified that the $200 million figure was provided by witness De May as an appropriate number to accomplish the objectives that he had in mind. The Company did not provide any specific numbers that comprise the $200 million. Tr. Vol. 9, p. 38. Witness Fountain could not identify any specific regulatory assets the Commission could select for accelerated amortization. Tr. Vol. 9, p. 90. Witness Fountain acknowledged that the Company is merely trying to achieve a particular financial metric for its cash flow. Tr. Vol. 9, p. 90.

On March 19, 2018, Public Staff witness Boswell filed her Second Supplemental Testimony. In addition to explaining the current differences between the Company's and the Public Staff's revenue requirement proposals and to refine the outside services adjustment, she addressed DEC's income tax proposal. She explained that while the Company has incorporated the known and measurable reduction in income tax expense associated with the decrease in the federal corporate income tax rate, the Company appears to have made the refunding of known and measurable tax dollars owed to ratepayers contingent upon increasing annual expenses by $200 million per year for an unknown number of years through the acceleration of depreciation for as yet unknown assets or through accelerating the amortization of costs associated with coal ash basin closures. Tr. Vol. 26, p. 634. She also noted that the Company has calculated the known and measurable refund of protected Federal EDIT based upon tax normalization rules. However, regarding unprotected Federal EDIT, she stated that the Company has proposed an amortization of approximately 82% of its unprotected Federal EDIT over 20 years, with the remaining 18% amortized over five years.

Thus, the Company's and the Public Staff's proposals differ as to: (1) the rate at which unprotected Federal EDIT should be flowed back to ratepayers; and (2) whether it is appropriate to increase the Company's revenue requirement by $200 million to accelerate depreciation of unknown and unspecified assets or legacy meters, or accelerated amortization of coal ash costs. Tr. Vol. 26, pp. 634-35. Witness Boswell noted that the Company does not dispute that the Commission has the discretion to flow back all of the unprotected Federal EDIT over any time period it finds appropriate. Tr. Vol. 26, p. 636. Company witness De May testified extensively regarding the impact implementation of the Tax Act could have on the Company's credit quality and the importance of maintaining the Company's current, high credit rating. Witness De May explained that as a result of the Tax Act, Duke Energy Corporation, the parent Company of DEC, was placed by Moody's on negative credit outlook. Tr. Vol. 4, p. 541. He explained that a negative outlook is different from a ratings downgrade. Witness De May stated that it is "like a yellow light, a warning" (id.), signaling to the investment community that a ratings downgrade could materialize in the next 12 to 18 months. Id. The January 2018 Moody's Report states that the Tax Act is "credit negative" for the utilities sector because of its impact upon cash flow, and that among the companies most negatively impacted is Duke Energy Corporation, the parent company of DEC.

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January 2018 Moody's Report, pp. 1, 3. The Report specifically notes that the parent corporation's "consolidated cash flow credit metrics are currently weakly positioned and likely to be incrementally pressured by tax reform." Id. at 5.

While Moody's has not put DEC on negative credit outlook, as witness De May explained, "the risk to Duke Carolinas is not zero just because it was not named in the initial report." Tr. Vol. 4, p. 542. Witness De May testified that while DEC currently maintains "a very strong balance sheet," the Tax Act is biased toward the health of corporations, and because utilities are structured different than most corporations, the Tax Act impacts utilities negatively. Tr. Vol. 5, p. 82. As Moody's notes, "most utilities will attempt to manage any negative financial implications of tax reform through regulatory channels … [and that] actions taken by utilities will be incorporated into our credit analysis on a prospective basis." Moody's January 2018 Report, p. 3.

Moreover, witness De May elaborated, during cross-examination by counsel for CIGFUR III, on the negative impact of weakening the Company's balance sheet: "Duke Energy Carolinas' customers benefit from a strong utility company … [and] a weakening of the balance sheet is not in the customer's interest, and it does not support the Company's capital plan …." Tr. Vol. 4, pp. 436-37. He testified further, "[u]ltimately, adverse cash flow impacts also have an adverse impact upon customer rates – DE Carolinas' customers benefit through lower electricity rates when the Company has lower financing costs, greater access to capital, and more timely cash recovery of its investments." Id. at 88-89.

The Company has proposed a 20-year flowback of unprotected but property-related EDIT. The Public Staff has criticized this aspect of the Company Proposal on several grounds. First, Public Staff witness Boswell asserted that the Company has "artificially" created the class of unprotected property-related EDIT. Tr. Vol. 26, p. 636. Witness De May explained that the 20-year period in the Company Proposal is tied directly to the underlying assets that created the deferred tax balances that became Federal EDIT when the Tax Act dropped the corporate income tax rate to 21%. As witness De May testified:

> I would say that from a theory perspective, those excess deferred taxes actually have a life. When I described to you what happened in a single asset where we collect from customers before we pay the government and then we're paying the government, but not collecting from customers, that is something that is dealt with through normalization. But there's a life to that; there's a life cycle to that, and protected and unprotected property related deferred taxes are no different except for the fact that they come from two places in the Internal Revenue Code and the statute protects one and it doesn't the other.

Tr. Vol. 5, p. 78. Witness De May testified further in response to questions from Commissioner Brown-Bland that he trusted "firmly in the theory behind the flowback of excess deferred taxes over the life of the underlying assets" (id. at 102-03.), that the normalization concept underlying the 20-year flowback proposal was discussed at length

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in the GAO Report, and that "normalization exists for a reason …." Id. at 103. Witness De May testified that normalization balances the customer and Company interests; it protects the Company's cash flow and also protects the customer against rate volatility, because the deferred balance acts as an offset to rate base, and, therefore, a reduction in rates. Id. at 104.

Also, as both the GAO Report and witness De May noted, deferred taxes represent an interest-free loan from the government that the Company then used, at no cost to customers, to invest in its business. Tr. Vol. 5, pp. 72-73. Witness De May explained that by making these investments, customers saved capital costs by the Company using an interest-free loan from the government rather than investor-supplied capital. However, witness De May testified that because these funds have been invested there is not a readily available reserve pool from which the cash needed to flow back the EDIT can be drawn and the Company would have to enter into financings to flow back EDIT in two years as originally proposed by the Public Staff. Id. at 79. He explained that it helps avoid volatility in customer rates. Id. at 80. Witness De May stated that, "[i]f we flowback these excess deferred taxes instantly or over a two-year period, you would see a dramatic reduction in customer rates followed by a snapping back of rates" and then a faster growth in rates due to the higher rate base. Id.

The Public Staff also raised generational equity concerns in advocating for a shorter flowback time period. EDIT funds, it indicated, "rightfully belong to the ratepayers and should be returned to them as soon as reasonably possible." Tr. Vol. 26, p. 637. Witness De May responded, ". . . we have to think about how that balance got created." Tr. Vol. 5, p. 73. Witness De May noted that it was created because of tax deferral, and the funds so generated then were invested in the business. Id. The Company argued that normalization, or the gradual return of EDIT over the life of the capital asset being depreciated, actually fosters generational equity by spreading the depreciation benefit over that time period.

The Company asserted that the Public Staff's proposed 5-year flowback would negatively impact its credit metrics. Tr. Vol. 5, p. 86. DEC maintained that, in fact, Hinton Cross Examination Exhibit 1 indicates that the relevant FFO/Debt ratios for the Public Staff Proposal over the Company's five-year planning horizon would fall below the 25% threshold, which the most recent Moody's report on DEC warned could result in a possible downgrade. See Moody's October 2017 Report, p. 2.

Finally, the Public Staff criticized the Company Proposal on the basis that in the last major overhaul of the Tax Code in 1986, the Company proposed and the Commission accepted a 5-year flowback of unprotected EDIT. See Order Allowing Rates to Become Effective (Stipulated 1987 Order), dated December 4, 1987, filed in Docket Nos. M-100, Sub 113 and E-7, Sub 415.

The Company, however, noted some differences between the 1986 tax law and today's Tax Act. First, DEC asserted that the total amount of the North Carolina retail portion of unprotected Federal EDIT is approximately $953 million, and in 1987, the North Carolina retail portion of unprotected Federal EDIT was approximately $28 million. See

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Application by Duke Power Company for Authority to Decrease Electric Rates and Charges (Stipulated 1987 Application), dated November 13, 1987, filed in Docket No. E-7, Sub 415. Also, as witness De May testified, the magnitude of the reduction in tax rates was smaller in 1986 – the reduction was from 46% to 34%, a 26% decrease, while today the reduction was from 35% to 21%, a 40% decrease. Tr. Vol. 4, p. 446. Finally, DEC argued that the general business environment was different as well. Witness De May testified that in 1986, the Company experienced 5-6% customer growth and today it is half of a percent. Id. at 448. See De May – Public Staff Cross-Examination Ex. 21, Slide 24. Witness De May also stated that the Company is "experiencing environmental challenges unlike anything we had in 1986." Tr. Vol. 4, p. 448.

According to DEC, another credit supportive measure is the third component of its Proposal, which mitigates the negative cash flow impact of Federal EDIT flowback by increasing revenue requirements by $200 million annually. The Public Staff indicated that it is "adamantly opposed" to this part of the Company Proposal. Tr. Vol. 26, p. 639. The Public Staff argued that adoption of this part of the proposal would "virtually" wipe out the "entire" benefit to customers. Id. The Company, however, has noted that customers will benefit under the Company Proposal by $107 million per year. Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1. This component of the Company Proposal provides for early collection of regulatory assets – that is, from the customer perspective, liabilities otherwise owed to DEC by customers. Tr. Vol. 4, p. 445. Witness De May explained that extinguishing these liabilities has a beneficial effect on the Company's cash flows, but also means that customers will pay less in the future. Id. DEC maintained that accelerated payment also reduces the carrying cost of those regulatory assets, again lowering customer charges. Moreover, the Company noted that the Moody's January 2018 Report forecasted this exact type of regulatory outcome, which Moody's predicts will be credit supportive as utilities work through regulatory channels to manage the negative financial implications of tax reform, stating: "For example, to offset a decline in cash flow, utilities could propose to regulators additional investments that benefit customers or accelerate recovery of regulatory assets." Moody's January 2018 Report, p. 3.

The AGO asserted in its post-hearing brief that as a result of recent reductions in the federal corporate income tax, DEC's costs are much lower going forward and it has accrued a large sum in federal deferred taxes that it no longer needs. The AGO argued that these cost reductions should be flowed through to ratepayers promptly. The AGO recommended that the Commission reject DEC's problematic proposals and approve utility rates that promptly flow through the benefits for customers. The AGO stated that it concurs with the testimony given on behalf of DEC's ratepayers, who advocate a prompt reduction in the Company's revenue requirement to account for the cost of service impact.

The AGO maintained that the extra $200 million increment sought by DEC should be rejected, because by deviating from the statutorily mandated ratemaking formula, DEC would establish rates that are inflated by design. The AGO asserted that fixing rates that are intended to over-collect revenues is contrary to the ratemaking formula in N.C. Gen. Stat. § 62-133(b) and (c), and violates key ratemaking principles. The AGO stated that

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the Commission's responsibility is to "fix such rates as shall be fair both to the public utilities and to the consumer." N.C. Gen. Stat. § 62-133(a). The AGO further stated that the statutory intent is that the Commission "fix rates as low as may be reasonably consistent" with Due Process constitutional considerations.[49] The AGO asserted that the burden of proof is on the utility to show that its proposed changes in rates are just and reasonable according to N.C. Gen. Stat. § 62-75; 62-134(c) and that DEC cannot meet that burden.

The AGO noted that Commission precedent and North Carolina case law support the prompt flow-through of tax reform benefits to utility ratepayers. The AGO noted that when Congress passed the Tax Reform Act of 1986, the Commission found that the significant reduction to the tax rate would "have an immediate and favorable impact on the cost of providing … public utility services to consumers in North Carolina," and concluded that "[i]t is incumbent upon this Commission to take the appropriate action as required so as to preserve and flow through to ratepayers, as a reduction to public utility rates, any and all cost savings realized in this regard which would otherwise accrue solely to the benefit of the stockholders." Order Initiating Investigation In the Matter of the Tax Reform Act of 1986, issued October 22, 1986 in Docket No. M-100, Sub 113, at 1. The AGO noted that, affirming the Commission's final decision in that proceeding, the North Carolina Supreme Court observed that the purpose of the Commission's proceeding in 1986 was to "take the effect of the reduction in tax rates and flow it through to the ratepayers." State ex rel. Utils. Comm'n v. Nantahala, 326 N.C. at 197, 388 S.E.2d at 122.

The AGO stated that, similarly, when the North Carolina legislature adopted tax reform in 2013, it intended for the benefits of reduced state income taxes to be flowed through to ratepayers as the tax changes occurred. See In the Matter of Implementation of House Bill 998 – An Act to Simplify the North Carolina Tax Structure and to Reduce Individual and Business Tax Rates in Docket No. M-100, Sub 138.

The AGO maintained that furthermore, although DEC has claimed that customers may be harmed by the reduction to its cash flow prompted by a reduction in rates, the evidence in support of that hypothetical position was not substantiated. The AGO stated that the Tech Customers witnesses Brown-Hruska and Strunk reviewed claims by DEC witness De May that the Company's funds from operations to debt (FFO/Debt) ratios would drop to the point that a downgrade would likely occur. The AGO stated that based on their review of the projected FFO/Debt ratios proffered by witness De May and the most recent credit assessment from Standard & Poors, they concluded that DEC's credit metrics would not be jeopardized by the elimination of the additional $200 million in cash flow. Tr. Vol. 26, p. 514.

The AGO noted that, rather, the Company's projections demonstrate that the Company is on track to maintain and even to exceed, after implementation of the Tax Act, FFO/Debt ratios in the range of 24 to 26 percent, which is the base case assumption

[49] State ex rel. Utils. Comm'n v. Duke Power Co., 285 N.C. 377, 388, 206 S.E.2d 269, 276 (1974) (Duke Power).

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relied upon by S&P before the Tax Act became law. Consequently, the AGO recommended that the Commission reject DEC's request for a $200 million annual increase in its revenue requirement.

The AGO noted that another impact of the federal income tax rate reduction is that it prompts a large reduction in the amount of accumulated deferred income taxes that DEC has accrued. The AGO stated that DEC acknowledges that customers should benefit from the excess accumulation. The AGO stated that, nonetheless, DEC proposes to spread out the return of most of the excess over many years, so that its rates are not reduced as much as they would be if the excess is returned promptly.

The AGO stated that it supports a return of the excess deferred taxes as soon as possible, but in no event longer than the initial recommendation of the Public Staff to return the excess deferred income taxes over 2 years because ratepayers will benefit immediately from the use of the amounts they are owed. The AGO argued that DEC has not supported its claim that any harm will fall to customers by the prompt return of the funds, and it is time for DEC to stop relying on excess revenues or a loan from its customers to maintain the overly flush cash flow that was provided under former tax deferral policies. The AGO asserted that the alternative of not returning dollars to consumers who struggle to pay their bills, or to consumers who would use their money for different purposes if given the opportunity, results in an undue burden on ratepayers and communities in North Carolina.

CIGFUR III stated in its post-hearing brief that the Commission should reject DEC's proposal to prolong the return of unprotected PP&E EDIT to ratepayers over a period of 20 years and should implement the Public Staff's proposal to return all unprotected EDIT over a five-year period.

CIGFUR III stated that in the early years of a given capital asset, the utility collects more in tax expense from ratepayers than it pays out to the IRS due to the difference in accelerated depreciation for tax purposes and straight-line depreciation for ratemaking purposes; that situation reverses once the ratemaking depreciation expense begins to exceed the tax depreciation. CIGFUR III noted that assuming that tax rates stay constant, over the life of a capital asset, the total tax expense paid by the ratepayers to the utility should match the tax expense the utility pays in federal taxes. CIGFUR III maintained that as a result of the differences in depreciation timing and because tax funds are ratepayer supplied, in the early years of a given capital asset ratepayers provide the utility an interest-free loan, reflected as a credit to the utility's ADIT liability account. CIGFUR III noted that due to the Tax Act, DEC's future tax liabilities will not be as high as anticipated when DEC filed its general rate case in August 2017, and the amount by which DEC's current ADIT balances exceed their future income tax liability because of the Tax Act are the EDIT at issue.

CIGFUR III stated that while certain EDIT have been designated by the IRS code as "protected" and are required to be normalized over the remaining life of the asset, the Commission has wide discretion in the timing and duration of the return of "unprotected"

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EDIT. CIGFUR III recommended that the Commission conclude that unprotected EDIT should be promptly flowed back to ratepayers; however, the Company proposes to delay returning what it designates as unprotected PP&E EDIT, although it concedes that this category of EDIT is not subject to IRS tax normalization rules. CIGFUR III stated that it opposes delayed return of unprotected EDIT and supports the Public Staff's recommendation that the unprotected EDIT be returned to ratepayers over 5 years.

CIGFUR III argued that the tax normalization rules are very clear and either EDIT is protected, or it is not. CIGFUR III asserted that the EDIT that the Company designates as "PP&E-related" is still clearly unprotected; a fact conceded by the Company. CIGFUR III stated that the Company's assertion that it should only return this PP&E-related unprotected EDIT over the same period of time it would have paid the funds to the IRS had the tax law not been passed is not supportable by any logical accounting or ratemaking principle, and should not dictate this Commission's decision as to what is a reasonable amount of time within which to return these funds to ratepayers. CIGFUR III asserted that these funds rightfully belong to the ratepayers and should be returned to them as soon as reasonably possible.

CIGFUR III maintained that while DEC stated that the delayed refund of unprotected EDIT is needed to protect its FFO/Debt ratio and thus its credit metrics, it has failed to offer compelling evidence in support of this justification. CIGFUR III asserted that to the contrary, Public Staff witness Hinton testified and concluded that, "it is unlikely that spreading the EDIT over five years will result in a debt rating downgrade and it is reasonable and fair to Duke's ratepayers and the Company." Tr. Vol. 22, p 277. As such, CIGFUR III urged the Commission to adopt the Public Staff's proposal to return all unprotected EDIT over 5 years.

CIGFUR III also recommended that the Commission reject DEC's proposal to "smooth out rate volatility" by slowing the flowback of benefits to ratepayers by accelerating the depreciation of ill-defined assets amounting to $200 million per year. CIGFUR III noted that DEC has requested this $200 million annual increase to its revenue requirements to collect expenses related to AMR meters, coal-fired plants, or coal ash clean up on an accelerated basis; specifically, the Company contended that its requested $200 million annual increase in its revenue requirement is required to mitigate the negative cash flow impact of the revenue requirement reductions resulting from the Tax Act and protects the Company's pre-Tax Act credit quality. CIGFUR III contended that, however, to the contrary, witnesses Strunk and Brown-Hruska, testifying on behalf of the Tech Customers, contended that:

> [T]he projected FFO/Debt ratios, adjusted so as to eliminate the request for an additional $200 million in cash flow, do not jeopardize the Company's credit metrics. Rather, the Company's projections demonstrate that the Company is on track to maintain and even to exceed – <u>after implementation of the Tax Act</u> – FFO/Debt ratios in the range of 24 to 26 percent, which is the base case assumption relied upon by S&P <u>before the Tax Act became</u>

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> law. Consequently, we recommend that the Commission reject DEC's request for a $200 million annual increase in its revenue requirement.

CIGFUR III Brief, pp. 23-24.

CIGFUR III stated that as a result of the analysis performed by the Tech Customers witnesses and the Company's failure to present compelling evidence of financial harm, it contends that DEC's request to increase its annual revenue requirement by $200 million is unnecessary and should be rejected.

CUCA argued in its post-hearing brief that DEC's rates should be adjusted to give customers full credit for the reduction in the Federal corporate income tax rate from 35% to 21% contained in the Tax Act. CUCA asserted that giving the customers the full benefit of a 100% flow through of this federal income tax reduction will help to soften the economic blow to consumers' budgets that will result from any rate increase approved by the Commission in this case. CUCA noted that DEC, however, argued that the benefits of the Tax Act should not be 100% flowed through to the customers right away and instead, the customers should be required to accept a delayed payment of some of the benefits of the tax reduction while DEC makes other uses of the customers' money.

CUCA asserted that the "math in this situation does not require a rocket scientist to solve": Federal income tax rates are reduced from 35% to 21% and the "gross up" that DEC requires to account for income taxes is significantly reduced. CUCA stated that if the effective tax rates (like any other item of expense) go down, it has to follow that the utility's revenue requirement also must go down. CUCA Brief, p. 15. CUCA argued that the revenue requirement impact of a reduction in the federal corporate income tax rate from 35% to 21% is a finite, calculable amount. CUCA asserted that customers should immediately receive, as soon as any new rates for DEC become effective, the full benefit of this tax reduction. CUCA opined that DEC should not be able to place a hold on what is, fundamentally, the ratepayers' money by any sort of delayed refund mechanism. CUCA maintained that such a delay puts ratepayers in the position of having to pay "phony" or "phantom" income taxes as a part of the overall utility revenue requirement. CUCA Brief, p. 15.

CUCA noted that DEC argued that, unless it could delay reducing rates by the full amount of the tax reduction, it would be forced into a position of having to borrow working capital funds and that its credit rating could be seriously undermined. CUCA noted that the Supplemental Testimony of the Tech Customers witnesses clearly refutes this argument. CUCA stated that the supplemental testimony shows that DEC will not experience any funding difficulties and will not incur any sort of erosion or damage to its credit rating.

CUCA asserted that to the extent the Commission allows DEC, as DEC has requested, to delay the full impact of the Tax Act tax reductions, then the customers and ratepayers are, in essence, being required to provide an interest free loan to the DEC stockholders. CUCA argued that if the Commission allows this, then the amounts of the

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Tax Act tax refunds that are not immediately flowed through should bear interest, to be ultimately repaid to the customers, at an annual rate of not less than 10% of the value of the delayed refund during the time of such delay. CUCA stated that that is the only way in which the ratepayers can be made whole for the loan they would be forced to make to the DEC stockholders. CUCA stated that, in addition, if DEC is allowed to delay the full impact of the tax refund implemented by Congress and the President, this delay will tend to reduce the business, financial, and operating risks of DEC. CUCA argued that, therefore, in addition to the payment of interest, the Commission should reduce the rate of return on equity awarded to DEC because of the risk reduction.

The Justice Center et al. stated in their post-hearing brief that the recent changes to federal tax law give the Commission an opportunity to mitigate the impact of any rate increase on the Company's most vulnerable customers. The Justice Center et al. noted that DEC has collected a large pool of unprotected EDIT. The Justice Center et al. urged the Commission to direct $5 million of the EDIT to the Helping Home Fund, which provides efficiency upgrades to low-income customers, for each year of the period over which the EDIT is amortized to flow back to ratepayers. The Justice Center et al. argued that at the same time, the Commission should reject DEC's request to retain $200 million in ratepayer dollars per year as cash-flow protection for the Company.

The Justice Center et al. noted that at the Greensboro public hearing, the executive director of the NCCAA, Sharon Goodson, recommended that the Company contribute up to $5 million annually to the Fund. Tr. Vol. 2, pp. 21-22; Goodson Ex. 1. The Justice Center et al. asserted that a $5 million annual contribution from DEC's unprotected EDIT represents less than 14 percent of the total unprotected EDIT that will flow back to ratepayers, and a smaller percentage of the overall EDIT that is owed to ratepayers.

The Justice Center et al. maintained that there is precedent for using a regulatory liability for the benefit of customers to fund energy-efficiency investments for the utility's low-income customers. The Justice Center et al. noted that the Helping Home Fund itself was originally funded with $10 million of a $20 million regulatory liability from DEP held for the benefit of its North Carolina retail customers.

In addition, the Justice Center et al. stated that sound policy reasons support directing a meaningful portion of the unprotected EDIT for targeted investments in low-income energy efficiency, rather than simply flowing all of the funds to ratepayers through rebates or a decrement rider. The Justice Center et al. maintained that utility investments in energy efficiency help to alleviate high energy burdens faced by low-income households, particularly when those households are faced with rate increases. The Justice Center et al. argued that low-income households, racial minorities, renters, and low-income customers residing in multifamily buildings experience higher than average energy burdens, meaning that they pay a higher percentage of their income on energy bills than their counterparts. The Justice Center et al. asserted that the Southeast faces some of the highest energy burdens in the nation and that households with high energy burdens must face difficult trade-offs between paying utility bills and paying for other necessities such as food, prescriptions, transportation, and medical care.

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Tr. Vol. 8, pp. 33-38. The Justice Center et al. also stated that low-income households are more likely than the average household to have older and less efficient appliances. The Justice Center et al. stated that by lowering energy costs during periods of high demand, and avoiding or deferring the need to build or upgrade expensive new power plants and transmission infrastructure, investments in energy efficiency also bring system-wide benefits that are shared by all customers. The Justice Center et al. stated that each dollar invested in energy efficiency yields up to four dollars in benefits for customers.

The Justice Center et al. noted that at the evidentiary hearing in this matter, DEC witness Fountain recognized that it would be appropriate for the Commission to direct a portion of the unprotected EDIT for the benefit of low-income customers. The Justice Center et al. stated that when asked whether the Company would object to allocating a portion of unprotected EDIT to the Helping Home Fund, witness Fountain agreed that the Commission could use a portion of the unprotected EDIT for low-income energy-efficiency measures: "the Tax Act is a tool that the Commission has before it that it can use to mitigate customers' rate impacts in a variety of different ways, and…there could be some considerations for low-income customers….it's a very useful tool for the Commission to be able to have." Tr. Vol. 7, p. 57. The Justice Center et al. stated that, moreover, witness Fountain agreed that there was precedent for using a regulatory liability held by the Company for the benefit of ratepayers to support the Helping Home Fund. Id. at 58. The Justice Center et al. noted that Commissioner Patterson asked witness Fountain whether the Helping Home Fund has been favorably received and whether DEC had considered making additional contributions to the Fund in the context of this general rate case. Tr. Vol. 9, pp. 111-12. The Justice Center et al. maintained that while witness Fountain praised the program, he acknowledged that the Company has made no commitment to further support the program from shareholder dollars or otherwise in this rate case.[50] Id. The Justice Center et al. stated that similarly, Commissioner Clodfelter and Chairman Finley urged DEC to consider additional ways to meet the needs of low-income customers, including consideration of the Ohio Percentage of Income Payment Plan and the Missouri "Dollar More" program. Tr. Vol. 9, pp. 97-98; 114-15.

The Justice Center et al. maintained that DEC's failure to offer any assistance to its low-income customers to mitigate the effects of its proposed increase in rates and charges should be relevant to the Commission's decision whether to grant any of those requested increases. See, e.g., Order Granting General Rate Increase, Docket No. E-2, Sub 1023, p. 82 (May 30, 2013) (finding that funding of low-income assistance programs "is a just and reasonable measure to mitigate the impact of the proposed rate increase on . . . low-income customers"). The Justice Center et al. noted that the potential impact of new rates on customers is a "critical consideration" in the Commission's determination on whether to accept those new rates. Cooper, 366 N.C. at 495, 739 S.E.2d at 548 (holding that the Commission must consider the impact of changing economic conditions on customers when determining return on equity for a public utility). The Justice Center

[50] On June 1, 2018, DEC made a shareholder-funded commitment of $4 million for programs including those to assist low-income customers.

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et al. asserted that to the extent that the Commission grants any component of DEC's request for a rate increase, it would be reasonable to order the allocation of $5 million per year of DEC's unprotected property, plant, and equipment EDIT to the Helping Home Fund for as long as that EDIT is amortized to flow back to ratepayers.

Kroger asserted in its post-hearing brief that customers should receive the full benefit of the tax savings provided by the Tax Act. Kroger noted that the reduction in the corporate income tax rate per the Tax Act will reduce DEC's federal income tax expense for regulatory purposes and that this reduction in tax expense should directly reduce the revenue requirement in this case. Kroger stated that viewed in isolation, this single component of the change in tax law, i.e., the reduction in the tax rate from 35 percent to 21 percent, reduces DEC's revenue requirement by a significant amount.

Additionally, Kroger noted that the Tax Act has implications for DEC's ADIT. Kroger stated that DEC accumulates these deferred income taxes in the ADIT on its regulatory books in an amount equal to this anticipated future tax liability. Kroger asserted that now that the corporate income tax rate has been reduced by 40 percent, DEC's anticipated future tax liability has also decreased by a comparable amount. Kroger noted that as of January 1, 2018, when the new tax rates became effective, a substantial portion of the ADIT on DEC's books will be considered to be "excess" ADIT. Kroger asserted that this excess ADIT should be returned to customers.[51]

Kroger recommended that the Commission reduce the revenue requirement in an amount that provides customers with the full benefit of the tax savings provided by the Tax Act and that the Company's revenue requirement in this case should be adjusted to reflect the direct impact to its cost-of-service and excess ADIT should be credited to customers starting with the rate effective period in this general rate case.

NCLM noted in its post-hearing brief that its witness Brian W. Coughlan provided testimony that DEC's rates should be adjusted downward to account for the significantly lower corporate income tax rates that DEC will pay since the enactment of the Tax Act. Tr. Vol. 8, pp. 105-107. NCLM noted that its Settlement Agreement with DEC did not resolve the issues raised by NCLM as to adjusting all rates downward to account for the lower corporate income tax rates in the Tax Act. NCLM stated that DEC's unanticipated tax savings should be used to mitigate any rate increase.

NCLM stated that its witness Coughlan addressed this issue in his testimony to supplement the Commission's work in Docket No. M-100, Sub 148. Tr. Vol. 8, pp. 105-107. NCLM noted that witness Coughlan simply asserted that, "[t]he new tax cuts should be taken into account now. The new tax rates take effect before the new electric rates will take effect. If the new tax rates are not accounted for at this time, DEC will have significantly higher than expected and appropriate earnings, and DEC customers will pay unfairly high rates between now and the next rate case." Id. at 106. NCLM respectfully requested that the Commission allow rate payers to benefit from the tax cuts to the maximum extent possible in this docket.

[51] Direct Testimony of Kevin Higgins, pp. 6-7.

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The Tech Customers asserted in their proposed order and post-hearing brief that the Commission is required in this general rate case to, among other things, account for the Company's operating expenses for the test year, taking into account "evidence … tending to show actual changes in costs". See, e.g., N.C. Gen. Stat. §§ 62-133(b)(3) and (c). The Tech Customers stated that given this requirement, the effects of the Tax Act as to the rates charged by the Company should be addressed in this general rate case rather than the separate, generic proceeding that the Commission has initiated in Docket No. M-100, Sub 148. The Tech Customers asserted that the Public Staff's proposal for return of EDIT best balances the need to return tax overcollections to ratepayers as promptly as possible with the appropriate regulatory goals of avoiding adverse rate impacts for ratepayers and allowing sufficient time for DEC to manage its cash flow so as to avoid negative impacts to its credit metrics.

Further, the Tech Customers maintained that DEC's proposal to offset the reduction in its revenue requirement resulting from the Tax Act with $200 million in accelerated depreciation expense is not sufficiently supported in the record and raises significant legal and practical concerns. The Tech Customers argued that a decline in revenues resulting from a change in federal tax law does not, by itself, support the adoption of offsetting revenue increases where those increases are not independently justified and supported.

The Tech Customers noted that given that the issue relating to the implementation of federal tax reform was introduced into this proceeding after the filing of testimony by the parties, the parties have addressed this issue through supplemental testimony, examination at hearing, and in post-hearing briefing.

The Tech Customers noted that they offered Supplemental Testimony of witnesses Strunk and Brown-Hruska. The Tech Customers witnesses evaluated the reasonableness of DEC's contention that a $200 million annual increase in spending was necessary to support its credit metrics. The Tech Customers stated that based on the projected FFO/Debt ratios offered by DEC witness De May and a review of the most recent credit assessment of Standard and Poor's, witnesses Strunk and Brown-Hruska found that DEC's projected FFO/Debt ratios, adjusted to eliminate the request for an additional $200 million in cash flow, do not jeopardize the Company's credit metrics. Tr. Vol. 26, p. 514. The Tech Customers stated that, instead, their analysis study shows that DEC is on track to maintain, or even exceed, its stated FFO/Debt ratio goal after implementation of federal tax reform. Id. The Tech Customers maintained that witnesses Strunk and Brown-Hruska also compared DEC's FFO/Debt ratio to those of comparable companies, including those in witness Hevert's proxy group, and found that DEC's ratios are in line with, or above, those of the comparable companies and that its FFO/Debt ratios are among the healthiest among the proxy group companies both on a current and projected basis. Id. at 516-517. Based on this analysis, the Tech Customers noted that their witnesses concluded that DEC's rationale for its proposal was inconsistent with the financial forecasts it has provided in its own exhibits and not necessary to protect its current credit standing. Id. at 519.

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The Tech Customers stated that the Commission is required in this general rate case to, among other things, account for the Company's operating expenses for the test year taking into account "evidence . . . tending to show actual changes in costs." See, e.g., N.C. Gen. Stat. § 62-133(b)(3) and (c). The Tech Customers asserted that this statute suggests, if not mandates, that the Commission implement tax reform in this proceeding.

Further, the Tech Customers stated that they agree with the Public Staff's recommendations concerning EDIT. The Tech Customers stated that they do not find support in accounting or ratemaking principles for the distinction in unprotected EDIT advocated by DEC. The Tech Customers stated that the PP&E assets for which DEC seeks a 20-year amortization period, like other unprotected EDIT, are not subject to IRS normalization rules. The Tech Customers asserted that Congress intentionally excluded EDIT from unprotected assets from the treatment given to protected EDIT because the excluded assets do not have normal useful lives. The Tech Customers noted that DEC asserted that unprotected PP&E EDIT is similar in nature to protected EDIT (which is also related to PP&E) and therefore it is reasonable to flow it back over a similar period. Tr. Vol. 5, p. 78. However, the Tech Customers stated that they can discern no principled basis for distinguishing between the assets in the manner proposed by the Company and an examination of the specific assets in this category suggests that they include assets (e.g., casualty loss, depreciation lag, AFUDC debt, pension cost) with highly uncertain accounting lives. See DEC Response to Public Staff Data Request No. 155-3, filed March 22, 2018.

Moreover, the Tech Customers argued that 20 years is simply too long a period over which to return over-collected ratepayers' money, and DEC has offered no evidence suggesting otherwise. In this regard, the Tech Customers stated that they are sympathetic to the need to return tax over-collections as expeditiously as possible. See, e.g., Buckeye Pipe Line Co., 13 FERC ¶ 61267, 61594 (1980) ("Millions of the Americans who use [electricity] live in poverty or on very tight budgets. Those people are in no position to lend money to anybody. A state of affairs that compels them to supply . . . electric companies with long-term credit in amounts that may sometimes seem minuscule on a per capita basis to the affluent but that are almost always material to the poor and to those who are just getting by cannot be viewed complacently.").

The Tech Customers noted that DEC has also raised concerns about the impact of the EDIT flowback on its cash flow that it speculates could negatively impact its credit metrics. Tr. Vol. 5, pp. 67-83. While the Tech Customers acknowledged the concerns raised by DEC, as well as the benefits that ratepayers derive from the Company's strong credit profile, the Tech Customers recommended that the Commission conclude that DEC's evidence on this point is not compelling or convincing.

Moreover, the Tech Customers noted that the Company's concerns over cash flow and credit metrics are mitigated, to an extent, by the Public Staff's five-year flow back proposal that provides the Company with the benefit of removing the total amount of the

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unprotected EDIT credit from the rate base in the current case, which benefits the Company by increasing rates and thereby moderating any cash flow issues, to the extent they may arise. The Tech Customers asserted that the financing cost to the Company will be imposed ratably over the period that the EDIT is returned through the levelized rider.

Finally, the Tech Customers recommended that the Commission conclude that DEC's proposal to offset the reduction in its revenue requirement resulting from the Tax Act with $200 million in accelerated depreciation expense is not sufficiently supported in the record and raises significant legal and practical concerns. The Tech Customers maintained that a decline in revenues resulting from a change in federal tax law does not, by itself, support the adoption of offsetting revenue increases where those increases are not independently justified and supported. The Tech Customers asserted that aside from the desire to offset reductions resulting from the change in tax law, the Company has not offered any principled explanation of the need for accelerated depreciation nor has it offered any basis for applying special depreciation rates for particular assets. The Tech Customers noted that DEC does articulate concerns about adverse rate impacts on consumers, but the Tech Customers support a five-year return of EDIT that will help ameliorate adverse impacts resulting from the return of EDIT. Moreover, the Tech Customers maintained that as to DEC's credit metrics, record evidence suggests that DEC's projected FFO/Debt ratios, adjusted to eliminate the proposed additional $200 million in cash flow, will not jeopardize the Company's credit metrics. Tr. Vol. 26, p. 514. The Tech Customers stated that, instead, evidence suggests that DEC will be on track to maintain, or even exceed, its stated FFO/Debt ratio goal after implementation of federal tax reform without an annual $200 million revenue increase. Id.

In light of the parties' testimony and all of the evidence presented, the Commission finds and concludes that it is appropriate to: (1) recognize a $211,512,000 per year reduction in DEC's revenue requirement to reflect the current 21% Federal corporate income tax rate; (2) deny DEC's proposed $200 million per year credit metric mitigation measure; and (3) allow DEC to continue to maintain all EDIT related to the Tax Act in a regulatory liability account for three years or until its next general rate case, whichever is sooner, at which point it will be returned to DEC's customers with interest reflected at the overall weighted cost of capital approved in this case of 7.35%. The Commission concludes that this approach appropriately balances the interests of DEC and its ratepayers.

The evidence shows that there is some agreement between the parties regarding how to implement the effects of the Tax Act. The Company and the Public Staff agree upon the revenue requirement effect of the decrease in the corporate income tax rate, the repeal of the manufacturing tax deduction, and the elimination of bonus depreciation. No party disputes the amounts presented by the Company and the Public Staff regarding the impact of the Tax Act on these issues, and the Commission finds and concludes that the revenue requirement changes presented by the Company and the Public Staff related to these issues are appropriate and should be approved. This decision results in a $211,512,000 per year reduction in DEC's revenue requirement.

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Further, the Commission gives great weight to the testimony of the Public Staff, the AGO, CIGFUR III, the Justice Center et al., Kroger, NCLM, and the Tech Customers that DEC's proposed $200 million per year credit metric mitigation measure is inappropriate and should be denied. Therefore, the Commission declines to allow the Company to include an additional $200 million in its annual revenue requirement for the purpose of offsetting the impacts of the Tax Act on DEC's revenue requirement.

The Commission agrees with the Public Staff that DEC's request amounts to essentially eliminating the benefit of the corporate income tax decrease on the Company's ongoing expenses. DEC's request for this extraordinary relief was presented in very vague and uncertain terms; the Company simply mentioned a few possible uses for the additional $200 million in annual revenue. None of the Company witnesses could even articulate the reason for the $200 million number, nor could they provide a breakdown of what that number represents, other than that witness De May felt the number to be appropriate. The Commission further agrees with the Tech Customers that a decline in the tax rate does not support the adoption of an offsetting revenue requirement increase that is not independently justified and supported. The Commission also agrees with the Tech Customers that adoption of the $200 million proposal would raise significant legal and practical concerns. Moreover, as noted by the Public Staff, the request was not time-limited; in theory, the additional $200 million in revenue requirement would equate to $1 billion after five years. Finally, the Commission finds and concludes that offsetting known and measurable reductions in taxes to be paid going forward against the recovery of unknown ongoing coal ash basin closure costs as ultimately proposed by DEC in its Post-Hearing Brief and Proposed Order in this docket in order to delay reflecting the current Federal corporate income tax rate in base rates constitutes inappropriate ratemaking.

The Commission finds that the $200 million in additional annual revenue requirement appears solely designed to arbitrarily inflate the Company's revenue requirement beyond the actual cost of service. The Company essentially seems to be telling ratepayers that they can receive the reduction in the tax rate, but they have to pay most of it back through accelerated depreciation expenses. The Commission rejects this proposal as arbitrary. The Commission is confident that the Company's management can navigate this situation without artificial and arbitrary adjustments to annual revenue requirement. The Commission concludes that the Company's request for an additional $200 million per year as a credit metric mitigation measure is not supported by the preponderance of the evidence and therefore is denied.

Finally, the Commission notes that DEC filed its rate case application in August 2017, four months before the enactment of the Tax Act. The Commission finds that it is appropriate to recognize this fact in rendering its final decision in this matter. The Tax Act is the most significant federal tax legislation since the 1986 Tax Act enacted some 30 years ago. Based on this fact and finding that the evidence presented by DEC concerning its credit metrics and a possible credit downgrade merit some weight, the Commission concludes that DEC shall maintain all of its EDIT in a regulatory liability account pending flow back of that liability to DEC's ratepayers with interest reflected at the overall weighted cost of capital approved in this case of 7.35% in three years or in DEC's next general rate case proceeding,

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whichever is sooner. If DEC has not filed an application for a general rate case proceeding by June 22, 2021, it shall file its proposal by that date to flow back to its ratepayers both the protected and the unprotected EDIT generated due to the Tax Act. The federal EDIT flowback proposal should include all workpapers that support the proposed calculations. The Public Staff is specifically requested to file comments on the proposal by no later than July 22, 2021. Other parties also may file comments on the proposal by no later than July 22, 2021.

The Commission notes that in the generic rulemaking proceeding established by the Commission to address the recent changes in the State corporate income tax rate (Docket No. M-100, Sub 138), the Commission concluded that EDIT for all utilities, as appropriate, were to be held in a deferred tax regulatory liability account until they could be amortized as reductions to income tax expense for ratemaking purposes in each utility's next general rate case proceeding. The Commission stated that it agreed with PSNC Energy's comments in that docket that recognizing the amortization of the EDIT in the next general rate case of a utility would provide for certainty as to the amount to be amortized instead of having to base the flow-back calculation on an estimate. In that proceeding, no party objected to that option of handling the EDIT. In addition, the Commission noted in its May 13, 2014 Order in the generic proceeding that both Carolina Water Service, Inc. of North Carolina (CWSNC) and Aqua had had open rate case proceedings at the time the generic State tax docket was initiated. A rate order was issued in CWSNC's rate case docket on March 10, 2014, and a rate order was issued in Aqua's rate case docket on May 2, 2014. The Commission concluded in the May 13, 2014 Order that the expense piece of the State corporate income tax rate change was reflected in the rates established in the CWSNC and Aqua open rate case proceedings, but that CWSNC and Aqua needed to adhere to the findings on State EDIT outlined in the May 13, 2014 Order. The May 13, 2014 Order concluded for the State EDIT that each utility was to hold the State EDIT in a deferred tax regulatory liability account until they could be amortized as reductions to income tax expense for ratemaking purposes in each utility's next general rate case proceeding. The Commission's decision herein is reasonably consistent with the treatment of CWSNC and Aqua in the generic State corporate income tax proceeding.

Further, the Commission notes that this process used in Docket No. M-100, Sub 138 has worked well and customers received or are receiving EDIT related to the State corporate income tax rate changes. In fact, in this proceeding, DEC and the Public Staff stipulated to begin returning (four years after the Commission's State EDIT decision in the May 13, 2014 Order in the generic rulemaking docket) to DEC's customers the State EDIT through a four year decrement rider.

In addition, the Commission notes that in the Commission's 1986 federal corporate income tax law change generic rulemaking proceeding (Docket No. M-100, Sub 113), the Commission concluded in its October 20, 1987 Order to Require Filing of Tariffs to Reduce Rates and Refund Plans to Effect Flow Through of Tax Savings for Those Regulated Companies not covered by Specific Orders on This Matter (1987 Order), as follows:

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> [t]hat the appropriate amortization of accumulated excess deferred income taxes will be considered in each company's next general rate case or such other proceeding as the Commission may determine to be appropriate. Any additional amounts relating to the adjustment that should have been made by the company for the flowback of excess deferred income taxes shall be placed in a deferred account and should ultimately be refunded to ratepayers with interest.

1987 Order. Although this conclusion was reached in a generic rulemaking proceeding, the Commission concludes that the fact that DEC had already filed its rate case application before the enactment of the Tax Act in this instant proceeding, it is appropriate to follow this same process for returning Federal EDIT to DEC's ratepayers.

However, the Commission, in its discretion, concludes that it is appropriate in this case to set a time limit for DEC to retain all of the EDIT generated due to the Tax Act. The Commission concludes that it is preferable to address this EDIT in a rate case proceeding; but due to the sheer magnitude of the EDIT that in total is approximately $2.14 billion, the Commission finds that DEC must begin the process to flow back the EDIT to ratepayers no later than three years from the date of this Order (or sooner if DEC files a rate case in less than three years). Therefore, the Commission concludes that if DEC has not filed an application for a general rate case proceeding by June 22, 2021, it shall file its proposal by that date to flow back to its ratepayers both the protected and the unprotected EDIT generated due to the Tax Act. The federal EDIT flowback proposal should include all workpapers that support the proposed calculations. The Public Staff is specifically requested to file comments on the proposal by no later than July 22, 2021. Other parties also may file comments on the proposal by no later than July 22, 2021.

In conclusion, the Commission finds it appropriate to: (1) recognize a $211,512,000 per year reduction in DEC's revenue requirement to reflect the current 21% Federal corporate income tax rate; (2) deny DEC's proposed $200 million per year credit metric mitigation measure; and (3) allow DEC to continue to maintain all EDIT related to the Tax Act in a regulatory liability account for three years or until its next general rate case whichever is sooner at which point it will be returned to DEC's customers with interest reflected at the overall weighted cost of capital approved in this case of 7.35%. The Commission concludes that this approach appropriately balances the interests of DEC and its ratepayers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 59-64

The evidence supporting these findings of fact and conclusions is found in the Company's verified Application, DEC's Petition for an Order Approving a Job Retention Rider (JRR), filed on August 14, 2017, in E-7 Sub 1152 (JRR Petition), the testimony of Company witness Pirro, the testimony of Public Staff witness McLawhorn, the testimony of other witnesses, the exhibits of witness Pirro, and the entire record in this proceeding. The Commission takes judicial notice of the Company's Initial and Reply Comments filed in Docket No. E-100, Sub 73 where the Company outlined the conditions that led to the

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loss of industrial jobs and where the Commission issued establishing guidelines on December 8, 2015. (JTR Order)

In its Petition, DEC requests approval of its JRR, a five-year pilot program for industrial customers that is intended to curtail further loss of industrial jobs in DEC's service territory. Petition, at p. 1. The Commission acknowledged the JRR's goal to stem further loss of industry, industrial production and industrial jobs in DEC's service territory as an important policy goal for North Carolina when it adopted the Guidelines for Job Retention Tariffs in Docket No. E-100, Sub 73. Petition at p. 3. Company witness Pirro testified in support of the Company's proposed JRR. Witness Pirro explained that the JRR will benefit ratepayers by retaining North Carolina jobs and strengthening local economies thereby aiding the commercial and residential markets. Tr. Vol. 19, p. 95. Since 2014, 50 manufacturing facilities served by Duke Energy have ceased operation in North Carolina. Id. at 78, 90. Witness Pirro states that the Company's IRP Update, filed on September 1, 2017 in Docket No. E-100, Sub 147, demonstrates the continuing struggles of manufacturing in North Carolina. Tr. Vol. 19, p. 90. He testifies that "[t]he Plan shows a steady decline in the number of industrial customers receiving electric service and our expectation [is] that even by 2023 industrial sales will still be below actual pre-recession sales realized in 2007." Id.

Witness Pirro also explained the eligibility requirements for the proposed JRR. Customers that use electric power as a principal motive power for the manufacture of a finished product, the extraction, fabrication or processing of a raw material, or the transportation or preservation of a raw material or a finished product would be eligible for the Company's proposed JRR. Id. at 90-91. Furthermore, in order to qualify for JRR, industrial customers must show that they (i) have or are considering the ability to shift production from their facilities to facilities in other states or countries; (ii) are considering a need to reduce the employment level at their facilities due in whole or in part to the impact of electricity cost; (iii) intend to reduce or are presently evaluating reduction of production levels or load due in whole or in part to the impact of electricity cost; or (iv) have load that is otherwise at risk of loss. Petition at p. 5. Additionally, eligible customers must have an aggregate electrical load of 3,000 kW or greater, in addition to other conditions described in the Petition and proposed JRR. Tr. Vol. 19, p. 91.

In its Petition, the Company does not seek recovery of the revenue reduction resulting from implementation of the JRR at this time, but instead requests deferral accounting with interest on the amount in excess of the $4.5 million that the Company will absorb on a one-time basis. Petition at p. 3.

CUCA witness O'Donnell testified in support of the Company's proposed JRR. Witness O'Donnell testified that if DEC continues to lose industrial load, the fixed costs of operating the DEC system will be shifted to the remaining customers in an amount even greater than the average 0.74% cited in DEC's Petition. Tr. Vol. 18, pp. 54-55. For example, witness O'Donnell calculated that if the Company's manufacturing load completely eroded, the remaining customers' rates would increase by over 16% annually.

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Id. at 55. He concluded that it would be much less harmful to residential customers to pay a 0.74% increase for five years than to have a permanent 16.22% increase. Id.

CIGFUR III witness Phillips also testified in support of the Company's proposed JRR. Witness Phillips testified that the Company's proposed JRR follows the Guidelines for Job Retention Tariffs issued by this Commission on December 8, 2015 in Docket E-100, Sub 73, and that the proposed JRR is in the public interest, and recommended that the Commission approve it. Tr. Vol. 26, p. 280. Witness Phillips testified that his review of DEC's historic and projected growth in customers indicated that within the 2007 to 2032 timeframe, the Company will see residential customers increase by 32.2%, commercial customers increase by 23.3%, and industrial customers decrease by 28.6%. Id. at 281. Witness Phillips testified that the proposed JRR will benefit all customers because "[i]f industrial load is lost, DEC would need to recover a larger portion of fixed costs from its remaining customers, resulting in higher electric rates for these customers." Id. at 282. Therefore, preserving jobs and industrial load through the Company's proposed JRR will strengthen the economy and keep electric rates lower for DEC's non-industrial customers. Id. Witness Phillips also testified that the Commission's guidelines in Docket No. E-100, Sub 73 do not exclude pipeline customers that are also important to the North Carolina economy. Id. at 283. Therefore, he testified that it would be unreasonable to impose restrictions on the Company's proposed JRR that exclude those customers. Id. at 284.

While the Public Staff is supportive of the JRR and believes that it is in the public interest, witness McLawhorn expressed several concerns regarding the proposed rider. Tr. Vol. 20, pp. 141-46. First, witness McLawhorn expressed concern with the availability of the rider to customers involved in the "transportation or preservation of a raw material of a finished product," which is understood to include gas pipeline customers. Id. at 141-42. He noted that pipelines are different than other industrial manufacturing facilities in that pipelines are fixed investments that are not easily relocated to another area, and unlike other industrial manufacturers, pipelines do not produce a finished product. Id. at 142. He recommended this disputed phrase be eliminated from the availability section of Rider JRR-1. Second, he argued that there are no specific criteria designated for use by the Public Staff to evaluate customer employment and financial records to aid in evaluating an applicant's justification for seeking the JRR thus depriving the Public Staff of the ability to verify the truthfulness of the information. Id. at 142-44. He also opposed the Company's request for deferral accounting of the revenue loss and the Company's proposal for sharing the discount between the Company's shareholders and ratepayers. Id. at 146. Lastly, witness McLawhorn recommended that the requirement that the discounted revenue must be used to retain jobs in North Carolina be more prevalently displayed in the Application form and that the language in the compliance filing clearly identify the length of the JRR from initial approval. Id. at 145-46.

Despite these concerns, the Public Staff generally supports the Company's proposed JRR, concluding that the rate reduction it provides for industrial customers would "assist them in maintaining jobs and load in North Carolina." Id. at 139-40. Witness McLawhorn testified that the Company's proposed JRR complies with the Commission's

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Guidelines for Job Retention Tariffs set forth in its December 8, 2015 order in Docket No. E-100, Sub 73. Tr. Vol. 20, pp. 134-38. Witness McLawhorn also testified that the proposed JRR is not unduly discriminatory because it is designed to reach the largest industrial customers, which impact other commercial and residential customer classes. Tr. Vol. 20, p. 138. Witness McLawhorn further stated that the proposed JRR "provides for a balancing of benefits and costs between those customers eligible for [JRR] and those that will bear the reduction in revenue that result from implementation of the rider." Id. at 139. Lastly, witness McLawhorn recommended that the impact of the rate discount be recovered from all retail ratepayers, including the customers eligible for the rate discount. Id. at 147.

Commercial Group witnesses Chriss and Rosa testified in opposition to the Company's proposed JRR. Witnesses Chriss and Rosa state that the proposed JRR fails to comply with Commission guidelines by limiting applicability to a subset of industrial customers and the rigor of verifying customer attestations is unclear. Tr. Vol. 26, p. 547. Witnesses Chriss and Rosa further request that if the JRR is approved, that it be extended to non-industrials that also provide jobs and have aggregate loads of 3,000 kW or greater. Id.

In its post-hearing Brief, Commercial Group continues to advocate a denial of the JRR. However, Commercial Group recognizes that the Commission approved a more limited JRR for DEP in DEP's rate case which included five safeguards, which the Commercial Group contends should be adopted in this case if approved. Commercial Group submits that the JRR would violate N.C. Gen. Stat. § 62-140(a) because it would unjustly discriminate among customers having an aggregate load of at least 3 MW based solely on whether the customer is an industrial customer. Commercial Group contends that this is a return to the Standard Industrial Classification (SIC) code distinctions that the Commission found discriminatory and rejected in prior proceedings. Commercial Group states that the Commission stated its concern in its final Order in DEC's 2011 rate case, Docket E-7 Sub 989, regarding the reasonableness and fairness of maintaining a rate differential based largely on labels such as the SIC codes. Commercial Group quotes N.C. Gen. Stat. § 62-140(a), and states that the legal standard is not whether a public utility can subject a customer to an unreasonable prejudice or disadvantage if doing so would be an advantage to other customers or the utility. Rather, the legal standard is that the public utility cannot grant any unreasonable preference or subject any person to any unreasonable prejudice or disadvantage. Further, Commercial Group contends that industrial customers are not a separate class of service because both industrial and commercial customers are members of the same OPT-V class, and that many non-industrial ratepayers in these classes have an aggregate load of at least 3 MW. According to Commercial Group, where the JRR's only distinguishing characteristic is industrial status, the JRR remains as unlawful and unduly discriminatory as the preference for OPT industrial customers that the Commission previously rejected, and, therefore, the JRR as proposed should be rejected as well.

In addition, Commercial Group states that the proposed JRR definitions and parameters that DEC selected provide only an illusion of being reasonable criteria for

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determining which customers should receive a rate subsidy. As an example, Commercial Group contends that the applicant could simply state that it has at some time in the past thought about obtaining the ability to move a portion of its operations out of state, but the applicant need not presently have such ability, presently plan to move operations out of state, nor be in such financial condition that jobs would be lost but for a JRR subsidy. Commercial Group further notes that the applicant does not need to maintain existing levels of employment, but instead chooses a level of employment that it states it will maintain, even if the level is lower than its present level.

Commercial Group notes that DEC witness Hevert gave convincing testimony that economic conditions in North Carolina have improved substantially since DEC's last rate case in 2013, and since the Commission adopted job retention guidelines in 2015. The unemployment rate in North Carolina and DEC's service territory has fallen substantially during these periods. Tr. Vol. 4, pp. 161, 165. Further, the correlation between the drop in unemployment in North Carolina and more broadly across the United States has been very high. Id. at 165. Moreover, DEC industrial customers already receive competitive rates that are below the national average and below the average in the Atlantic South region.

Commercial Group questions whether there will be a means to assess the effectiveness of the JRR. Commercial Group cites the testimony of Public Staff witness McLawhorn regarding the report that DEC will be required to file, and states that the report will not provide any reliable, independently verifiable information to determine the success or failure of the JRR. Based on the uncertainty of verifiable results from the JRR, Commercial Groups requests that the Commission should require the same safeguards that it required of DEP for its JRR in DEP's most recent rate case.

Company witness Pirro's rebuttal testimony responded to the concerns raised by other witnesses related the Company's proposed JRR. Witness Pirro agreed with the Public Staff's concern regarding difficulty evaluating customer financial and employment records. Tr. Vol. 19, p. 92. To address this concern, witness Pirro explained that DEC will impose a requirement that an officer of the customer sign the application and the signature be notarized. Id. Witness Pirro also noted that the guidelines don't require a demonstration of financial distress, but the discounted revenue must contribute to job retention in North Carolina. Id.

Additionally, witness Pirro testified regarding the inclusion of customers involved in the "transportation or preservation of a raw material of a finished product", that this language was included to allow the JRR to apply primarily to gas pipeline customers. Id. at 92. He stated that pipeline customers have expressed concerns with electricity costs and have requested rate relief to aid in their North Carolina operations. Id. DEC believes that it is reasonable to include this type of customer with manufacturing facilities when applying the JRR. Id.

Witness Pirro further testified that deferral accounting was requested because the timing and magnitude of the revenue reduction is unclear. Id. at 93. "The use of deferral

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accounting allows the Company to assess the true impact of the rider and seek recovery at a later date when revenues are more certain." Id. at 93-94. Witness Pirro also disagreed with witness McLawhorn's recommendation that the Company's shareholders absorb $4.5 million every year the rider is in effect. Id. at 95. Witness Pirro testified that the JRR will benefit ratepayers by retaining North Carolina jobs and strengthening local economies thereby aiding the commercial and residential markets. Id. While the Company's shareholders are willing to absorb a portion of the revenue reduction in the first year to implement the program, a requirement that shareholders absorb this cost in subsequent years would deprive the Company of a reasonable opportunity to recover its just and reasonable costs. Id.

Lastly, Witness Pirro agreed with witness McLawhorn's requested two changes to the application form and tariff. Id. at 93. He explained that the Company does not oppose the relocation of the statement regarding the discounted revenue being used to retain jobs in North Carolina to a more prevalent location in the Application. Id. The Company also does not object to more clearly identifying that the Rider terminate and no longer be available for service 5 years from the effective date of the Rider. Id.

In the Stipulation, the Company and the Public Staff agreed that "the Company's proposed Job Retention Rider generally complies with the Commission's guidelines adopted in Docket No. E-100, Sub 73, but two issues remain to be decided upon by the Commission: (1) whether companies involved in the transportation or preservation of a raw material or a finished product (e.g., pipeline customers) should qualify; and (2) how or if the Job Retention Rider should be funded after the expiration of the initial year's $4.5 million shareholder contribution." Stipulation, § II. c.

Except for the two unresolved issues stated above, the Stipulating Parties have agreed to the proposed JRR as described by witness Pirro in his rebuttal testimony, and further agreed that JRR revenue credits shall be recovered through a JRR Recovery Rider (JRRR) from all retail customers concurrent with JRR implementation, which is anticipated to occur approximately six months following the Commission's decision. Id. at 11, 13. The Stipulation provides that JRR and JRRR revenues shall be reported to the Commission annually and the JRRR shall be reviewed and will be subject to adjustment annually coincident with the September fuel adjustment to match anticipated recovery revenues and true-up any past over-or under-recovery. Id. at 13. Additionally, due to the uncertain date of implementation, compliance tariffs shall be filed prior to implementation of the JRRR and customers shall be notified by bill insert or message upon implementation. Id.

Company witness Pirro filed testimony and exhibits in support of the Stipulation. In his settlement supporting testimony, he explains that the recovery rate under the JRRR is set at $0.00041 per kWh to recover the first year of impact, less the $4.5 million absorbed by the Company, reduced by 10% for application lag. Tr. Vol. 19, pp. 107-08. Witness Pirro further testified that the JRRR is intended to keep the Company revenue neutral with respect to the JRR, other than the one-time $4.5 million contribution from

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shareholders, over the 5-year pilot period, and, if needed, a final true-up shall be applicable upon termination of JRR. Id. at 108.

The Commission finds and concludes that the Company's proposed JRR as modified by this Order is just and reasonable to all parties based on all of the evidence presented. The Commission finds that the continued loss of industrial jobs in DEC's service area will have a detrimental effect on the State. The Commission views the Company's proposed JRR as an effort to retain industrial jobs in North Carolina and concludes that implementation of the rider is in the public interest. As with other economic development tariffs previously approved by this Commission, approval of the JRR is based in part on an evaluation of the expected economic benefits resulting from the tariff. The Commission has considered the economic impact of the continuing decline of the North Carolina industrial base as well as the impact of the recovery rider on non-participating ratepayers, and concludes that the JRR strikes the appropriate balance between the two. The Commission concludes that by limiting the availability of the JRR to industrial customers, the Company has minimized the effect on non-participants while assisting the group of customers that are most in need of assistance. To further minimize the impact to non-participants and to achieve the goal of the JRR in the most cost-effective manner, the Commission shall limit the JRR to a one-year pilot, with the option of renewal for one additional year upon a showing that the JRR is achieving the intended objectives. Requiring the Company to show the Commission the effectiveness of the JRR in the rider proceeding removes any concerns expressed by the Commercial Group regarding measurement and verification. This reduction in the number of years for the pilot to one-year with the opportunity for a second year allows the Commission and the parties to assess the health of industrial sector as a whole after one year on the JRR and if an additional year would be in the public interest. In addition to the reduction of the pilot to one year, with the opportunity for a second year, the Commission determines that additional changes to the JRR are necessary for proper measurement and verification. First, the Company shall require the Customer to maintain an employment level of 90 percent of the its employees, with the number of employees determined by an average of its employment level over the twelve months prior to the filing of the Application and Agreement for the Job Retention Rider. The application shall state the specific number of employees and verify that this number represents 90 percent of the monthly average over the past twelve months. Second, the Customer shall submit in writing to DEC no later than March 1, and quarterly thereafter, a report verifying the employment level at the Customer's facility(s) receiving the Job Retention Rider credits. Third, if the Customer does not maintain the stated employee level, the Customer shall be removed from the tariff pursuant to the language in the proposed application and shall be required to refund the amount of benefits received under the JRR. DEC shall change the application language accordingly. The Commission has considered the arguments for expanding the JRR made by Commercial Group witnesses Chriss and Rosa, and concludes that expanding the JRR to other customer classes would place too large a burden on non-participants and would be unreasonable.

Furthermore, the Commission concludes that limiting the availability of the JRR to only industrial customers is not unreasonably discriminatory. Rather, it is based on a

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reasonable difference between customer classes, and the discount offered to participants under the JRR as compared to the amount of rider recovery on non-participants bears a reasonable proportion to the difference between the customer classes. See State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, 348 N.C. 452, 468, 500 S.E.2d 693, 704 (1998). Based on the evidence presented, the Commission finds that industrial customers' sales have been flat or declining since the recession, while residential and commercial sales are growing. Furthermore, a $0.003227 per kWh reduction in rates for participating industrials as compared to an increase in rates for the average retail customer of approximately $0.000539 per kWh per month under the JRR is proportionate to differences between these customer classes and reasonable given the economic and rate benefits of retaining industrial customers on DEC's system.

The Commission concludes that the JRR, with the modifications established in this Order, is in accordance with the requirements and guidelines the Commission previously established. In the JRT Order, the Commission directed utilities to "craft eligibility requirements that are narrowly tailored to meet the intended goals of maintaining jobs in the most economically efficient manner." Although the disputed phrase that allows for the eligibility for pipeline companies was included in the JRT Order as a possible example of eligibility criteria, the Commission is not persuaded that the eligibility criteria proposed by the Company is sufficiently narrow to ensure that the JRR will maintain jobs in the most efficient manner. Pipelines, which cannot relocate, are sufficiently different from other industrial customers and should be excluded from eligibility in the JRR. The disputed phrase "or the transportation or preservation of a raw material of a finished product" should be removed from the eligibility criteria.

The Commission further concludes that the customer attestations regarding certain eligibility requirements for the JRR, as modified by this order, are reasonable and adequate. Based upon the practical considerations of managing eligibility and how eligibility for certain rates is verified in other contexts, such as the opt-out process for DSM/EE rates, the Commission concludes that the Company's proposed method for verifying eligibility for the JRR is reasonable.

Commercial Group states that it does not take issue with the Commission's gradual approach to class revenue allocation, except if the Commission grants the proposed JRR. In that event, according to Commercial Group, the Commission should use any such reduction to move each customer class closer to its respective cost of service. The Commission does not agree with Commercial Group's position. The approval of the JRR does not eviscerate the principle of gradualism in reaching rate of return equilibrium among the customer classes. Further, the rate designs approved herein and the approval of the JRR will result in just and reasonable rates.

Finally, the Commission notes that the proposed JRR is a limited-term pilot, which will allow the Commission and the Company to follow the customers on the tariff and to consider whether the tariff meets its objectives of job retention and the related economic benefits. If it does not, then the JRR will not be continued beyond its one-year term. Except as modified by this order, the Commission finds that it is reasonable for DEC to

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implement JRR and JRRR as proposed in the Stipulation and Pirro Settlement Exhibit 1.

The Company, as well as ratepayers, benefit from the retention of industrial jobs, and the load related to the retention of the industrial jobs. In addition to the testimony in this case, this fact is further justified by the Company's indication in Docket No. E-100, Sub 73 that it was considering funding all or a portion of a JRT and provided comments on the necessary requirements for measurement and verification under the scenario of a fully Company-funded JRT. To achieve just and reasonable rates, if the pilot program is extended to a second year, it is appropriate for the Company to contribute to the JRR at the same level as year one. Therefore, the Company's recovery should be reduced by the amount of $4.5 million if the Commission determines in the rider proceeding that the JRR pilot program should be extended to a second year.

The Commission, therefore, concludes that the proposed JRR, as modified by this Order, is in the public interest, is not discriminatory and is consistent with the Commission's holding that "approval of a JRT is a matter of sound ratemaking policy to address the undisputed decline in industrial sales in North Carolina." Order Adopting Guidelines for Job Retention Tariffs in Docket No. E-100, Sub 73, at 22. If the JRR is extended an additional year and at the end of the second year the Company determines there is still a need for the JRR, nothing in this order prevents the Company for filing for a new JRR based upon the economic circumstances at that time.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 65-68

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the record in Docket No. E-7 Sub 1110, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

In Docket No. E-7, Sub 1103, DEC requested to defer its costs of complying with the Coal Ash Management Act (CAMA) and the EPA's Coal Combustion Residual Rule (CCR Rule, collectively CAMA) and notified the Commission that it had established an Asset Retirement Obligation (ARO).

In its March 15, 2017 comments in Docket No. E-7, Sub 1103, the Public Staff supported the Company's deferral request, provided that ratemaking treatment for the deferred amount would be determined in the next base rate case:

> In this particular case, the Public Staff believes that the non-capital costs and depreciation expense related to compliance with state and federal requirements cited in the Companies' petition generally satisfy the criteria for deferral for regulatory accounting (but not necessarily ratemaking) purposes. First, they are adequately extraordinary in both type of expenditure and in magnitude to justify consideration for deferral. Second, the effect of not deferring the expenses on the Companies' respective earned returns on common equity would be significant.

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Initial Comments of the Public Staff, at p. 6.

In the present docket, DEC witness McManeus noted that the Company had petitioned in Docket Nos. E-2, Sub 1103, and E-7, Sub 1110, for approval to defer certain costs incurred to comply with environmental requirements for Coal Combustion Residuals (CCR or coal ash). Tr. Vol. 6, p. 239. While various parties opposed recovery in rates of some of the coal ash costs, that is a separate issue from the deferral request. The deferral request was generally unopposed, and the Commission finds and concludes that deferral in a regulatory asset for previously incurred coal ash environmental costs is consistent with the Commission's criteria for deferrals and reasonable in the circumstances of this case.

In the present docket, Public Staff witness Maness indicated that the Public Staff continues to believe that prudently incurred CCR expenditures should be allowed to be deferred for regulatory accounting purposes. Witness Maness made several adjustments and with regard to the addition of a return on deferred coal ash expenditures from December 2017 through April 2018, DEC agreed with this adjustment (Tr. Vol. 6, p. 314), and it was not opposed by other witnesses. The Commission notes that new rates will not be effective by May 1, 2018, as might have been expected at the time of the filing of witness Maness' testimony; therefore, the Commission finds it appropriate and reasonable to extend the accrual of this return until the effective date of rates approved in this proceeding. Based on the foregoing, the Commission finds and concludes that a return based on the net-of-tax overall weighted cost of capital authorized in DEC's last general rate case should be added to the amount of deferred coal ash costs are approved in this Order for recovery in rates, and that the return should be applied through the effective date of the rates approved in this proceeding.

Additionally, as recommended by the Public Staff, the Commission concludes that use of the 2018 federal income tax rate of 21% is appropriate to calculate the 2018 portion of the carrying costs. With respect to Public Staff witness Maness' adjustment regarding mid-month cash-flow convention, DEC witness McManeus accepted this adjustment (Tr. Vol. 6, p. 314), and no other witness opposed it. The Commission finds and concludes that the mid-month convention for calculation of the return is reasonable and appropriate. Additionally, as recommended by the Public Staff, the Commission concludes that compounding of the carrying costs should take place at the beginning, rather than the end, of January of each year.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 69-72

The evidence supporting these findings and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony of the public witnesses, and the testimony and exhibits of the following expert witnesses: DEC witnesses Fountain, McManeus, Kerin, Wells, Wright, De May, Hager, and Doss; Public Staff witnesses Junis, Garrett, Moore, Lucas, Boswell, and Maness; AGO witness Wittliff; CUCA witness O'Donnell; and Sierra Club witness Quarles.

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The public witness testimony and expert witness testimony and exhibits regarding DEC's CCR costs are voluminous. The Commission has carefully considered all of the evidence and the record as a whole. However, the Commission has not attempted to recount every statement of every witnesses. Rather, the following is a complete summary of the evidence.

Likewise, the Commission has read and fully considered the parties' post-hearing briefs. However, the Commission has not in this order expressly addressed every contention advanced or authority cited in the briefs.

Based upon the evidence addressed below and in the exercise of its expert judgment and discretion, the Commission determines that a management penalty of approximately $70 million should be assessed for DEC's mismanagement of its CCR activities undertaken through the end of the test year as extended for reasons set forth hereafter.

Coal-fired power plants have played a predominant role in electricity generation by DEC throughout its history, and the Company is dependent upon coal-fired generation today. With coal-fired generation comes a by-product – coal ash, also known as coal combustion residuals, or CCRs. At least since the 1950s, standard industry practice, particularly in the Southeastern United States, has been reliance on coal ash basins. Such basins were constructed and used at all of the Company's coal-fired generating units.

The United States Environmental Protection Agency (EPA) has studied CCRs and their proper management and handling since the 1980s, but the agency only began moving forward on comprehensive regulation of CCRs less than ten years ago. In 2010, the EPA issued proposed rules regarding CCRs. EPA's final rule – the Coal Combustion Residuals Rule (CCR Rule) – was promulgated on April 17, 2015. North Carolina also enacted specific statutory requirements for coal ash management in CAMA, which became effective in 2014 and was amended in 2016. The CCR Rule and CAMA introduced new requirements for the management of coal ash. DEC, of course, must comply with these new requirements, which mandate closure of the Company's coal ash basins. Mandated closure triggers Generally Accepted Accounting Principles (GAAP) provisions relating to the retirement of long-lived tangible assets, and specifically triggers the requirement that the Company account for compliance costs through ARO accounting. The Company, as required by GAAP, established an ARO with respect to its coal ash basins, and, in accordance with the Commission's orders in Docket No. E-7, Sub 723, deferred the impacts of its GAAP-mandated ARO accounting. The Company now seeks recovery of the coal ash basin closure costs incurred to date in connection with CCR Rule and/or CAMA compliance, along with such costs it anticipates will be incurred annually on an ongoing basis. The Company's proposal has three component parts:

- First, DEC seeks recovery of the actual coal ash basin closure costs it incurred from January 1, 2015 through December 31, 2017. On a North Carolina retail

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jurisdiction basis, these costs amount to $566.8 million.[52] McManeus Rebuttal Ex. 3, pp. 36-37. The Company proposes further that, rather than recovering 100% of these already incurred costs immediately, it recover them over a five-year amortization period, and it seeks a return on the unamortized balance.

- Second, DEC seeks to recover on an ongoing basis $201.3 million per year in annual coal ash basin closure spend. This amount is based upon the NC retail jurisdiction portion of the test year (2016) coal ash basin closure expense incurred by the Company.
- Third, DEC seeks permission to establish a regulatory asset/liability and defer to this account the NC retail portion of annual costs that are over or under the costs established in connection with the Company's request that it be permitted to recover in rates on an ongoing basis its actual test year coal ash basin closure costs – i.e., the amount over or under $201.3 million, if the Company's proposal as detailed above is approved by the Commission. In addition, the costs incurred from January 1, 2018 through the date new rates set in this proceeding are effective would also be deferred to this account. The deferred amounts (including a return) would be brought into rates and recovered through future rate cases.

The Commission, as it has in prior rate orders, provides a review of the applicable legal principles, to provide a framework for the application of those principles to the facts of this particular case. See, e.g., 2013 DEC Rate Order, pp. 23-28 (in Duke Energy Carolinas 2013 Rate Case, Commission provided an extensive review of the "governing principles" regarding rate of return). For purposes of assessing the Company's coal ash basin closure cost recovery proposal, the applicable principles include (1) the general cost recovery framework and the role of the revenue requirement in that framework; (2) principles underlying "reasonable and prudent" costs; (3) principles underlying the concept of "used and useful," and (4) a discussion of the burden of proof, and, in particular, presumptions and the distinction between the burden of production (borne by Intervenors) and the ultimate burden of persuasion (borne by the Company).

In the recently-decided DEP rate case (Docket No. E-2, Sub 1142, the 2018 DEP Rate Case, or 2018 DEP Case), the Commission's decision summarized cost recovery based upon these principles, and found that for cost recovery the utility must prove that the costs it seeks to recover are "(1) 'known and measurable'; (2) 'reasonable and prudent'; and (3) 'used and useful' in the provision of service to customers." 2018 DEP Rate Order, p. 143. The same standard applies in this case.

The arguments raised by Intervenors in this docket challenge the inclusion of the Company's coal ash basin closure costs in rates because the costs are not "reasonable and prudent" and "used and useful," or on the theory that cost recovery should be shared by both the shareholders and ratepayers.

[52] This amount excludes any fines, penalties and other unrecoverable costs incurred by the Company. See Tr. Vol. 6, p. 259.

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Summary of the Evidence

A. Company Direct Case Overview and Costs Sought for Recovery

In his direct testimony, Company witness Fountain testified that DEC is requesting recovery of ash basin closure compliance costs incurred in the period from January 1, 2015 through November 30, 2017. Witness Fountain explained that the Company has removed costs related to its response to the Dan River release and is not requesting their recovery for them. Tr. Vol. 6, p. 174. Witness Fountain also testified on direct that, based on actual coal ash expenses incurred during the 2016 test year, DEC is seeking recovery of ongoing ash basin closure compliance spend of $201 million per year, with any difference from future spend being deferred until a future base rate case. He stated that including this revenue requirement will provide a measure of predictability to customers of future coal ash expense rate drivers. Id. at 174.

Company witness McManeus testified that Adjustment No. 18 to the Company's operating revenues and expenses amortizes the actual deferred costs incurred through December 31, 2017, in connection with compliance with federal and state environmental requirements related to CCRs, pursuant to DEC's petition in Docket Nos. E-2, Sub 1103 and E-7, Sub 1110 for authority to defer such costs in a regulatory asset account, over a five-year period. She explained that while the costs to comply with CAMA and the CCR Rule are largely duplicative, the Company has determined a small portion of the costs to be specific to CAMA, unique to North Carolina and appropriate for direct assignment to North Carolina. She stated that in the deferral calculation, for CAMA-specific costs, the adjustment separates out the portion allocable to the wholesale jurisdiction and directly assigns the retail portion to North Carolina retail. She stated that these costs were based on actuals at the end of the test period, updated through November 30, 2017.[53] The Company proposes to defer these costs over a five-year period and to earn a net of tax return on the unamortized balance. Witness McManeus testified that the expected deferred balance, based on total system spend on these costs during this period, plus applying allocation factors and incorporating the return on the deferred costs, is $524.0 million.[54] Witness McManeus clarified the Company seeks no recovery for fines, penalties, or costs of which DEC has agreed to forego in the deferral. Tr. Vol. 6, pp. 259-60, 279-80, 288-89, 297, 343.

Witness McManeus testified that Adjustment 19 increases O&M to reflect the expected ongoing annual level of expenses DEC will incur in connection with coal ash compliance costs represents the amount in ongoing annual coal ash basin closure expense (sometimes referred to in this Order as "ongoing compliance costs"). She explained that this number – $201.3 million on a North Carolina retail basis – is based upon actual test year (2016) spend, and stated that the Company is also requesting

[53] These costs were later updated to actual costs through December 31, 2017, and the deferred balance including return computed as of April 30, 2018. McManeus Rebuttal Ex. 3, pp. 36-37.

[54] This amount has been adjusted to $566.8 million based on the estimated deferral balance at April 30, 2018. McManeus Rebuttal Ex. 3, pp. 36-37.

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permission to establish a regulatory asset/liability and defer to this account the North Carolina retail portion of annual costs over or under the amount established in this proceeding. She explained that this will ensure that the Company only recovers from customers its actual level of spending related to coal ash. She also clarified that no fines, penalties, or costs of which DEC has agreed to forego recovery are included in this adjustment. Tr. Vol. 6, pp. 260-61, 279-80, 288-89.

B. Company Direct Case: Coal Ash Overview

Company witness Kerin described his management role with the Ash Basin Strategic Action Team (ABSAT), the umbrella organization created for Duke Energy companies to address the laws, regulations, and orders concerning the management of CCRs. Witness Kerin discussed how, during his work on the ABSAT team, he spent approximately 3,000 hours working exclusively on CCR issues, familiarizing himself with state and federal regulations dealing with CCR and historical industry practices and standards used to comply with such regulations. He described how he interviewed legacy employees who worked at, and with, coal combustion generating units and CCR handling sites, and reviewed historical company documents dealing with those facilities and sites in order to gain an understanding of how CCR handling standards inside and outside of the Company developed over time. Witness Kerin also described how he toured and inspected every CCR basin in Duke Energy's North and South Carolina jurisdictions, as well as CCR sites at Duke's Midwest sites, Dominion, AEP, and TVA. He detailed how he developed CCR evaluations for Duke Energy's CCR sites, and an industry peer group to discuss CCR issues generally, which continues to meet semi-annually. Witness Kerin concluded that during his time on the ABSAT team, he gained an understanding and knowledge of coal ash management practices at utilities across the country. Tr. Vol. 14, pp. 96-97.

Witness Kerin provided a detailed discussion of DEC's coal ash management history and practices and the new obligations imposed on the Company by the CCR Rule and CAMA. He explained that CCRs are by-products produced from the electricity production process lifecycle – the burning of coal – at coal-fired generation plants and include fly ash, bottom ash, boiler slag, and flue gas desulfurization (FGD) material. He stated that environmental regulations related to CCR management have evolved significantly over time, affecting how the Company has operated its coal-fired plants in compliance with those obligations. He maintained that at each step in the environmental regulatory evolution process, DEC was in line with industry standards and maintained that DEC reasonably and prudently managed CCRs and its coal ash basins. He explained that since its last rate case, DEC has become subject to both federal and state regulations that require it to take significant action to close its ash basins. Tr. Vol. 14, pp. 99-112.

Witness Kerin testified that since the early 1900s, DEC has disposed of CCRs in compliance with then current regulations and industry practices. Until the 1950s, CCRs were either emitted through, in the case of fly ash, smokestacks or, in the case of bottom ash, manually removed the ash from boilers and stored it in landfills. Since that time, the industry transitioned to a water sluice to remove ash from boilers, and to clean the

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electrostatic precipitators, preventing ash from being emitted through the smokestacks. This effluent, as well as FGD blowdown, was then diverted to ash basins, of which DEC has 17 in the Carolinas. In other words, in many cases, ash basins were actually created or relied upon to effectuate prior environmental regulations. In the mid-1970s, the enactment of the Clean Air Act and its subsequent amendment in the 1990s required electric utilities to capture more CCRs through the use of electrostatic precipitators (ESP) or bag houses and FGD blowdown. Tr. Vol. 14, pp. 99-112.

Witness Kerin provided a detailed history of coal ash regulation. He testified that the Clean Water Act of 1972 and the subsequent creation of the National Pollutant Discharge Elimination System (NPDES) permitting system, made wet ash handling and ash basins the primary lawful and effective way to meet CCR needs and environmental requirements from 1974 until 2015. Tr. Vol. 14, pp. 100, 106-09.

Witness Kerin testified that, in June 2010, the EPA proposed national minimum criteria to regulate the disposal of CCRs and the operation and closure of active CCR landfills and existing and inactive CCR surface impoundments. He stated that, approximately five years later in April 2015, EPA published the final CCR Rule in the Federal Register. He explained that the CCR Rule established national minimum criteria for CCR landfills and surface impoundments, which result in different impacts at each CCR unit, depending on site-specific factors, and testified to the exact nature of those criteria. He stated that the CCR Rule also contains requirements for how and when CCR basins must be closed, and that it provides for closure either by cap-in-place or removal of the ash. He noted that as stated in the CCR Rule, the EPA considers CCRs to be a non-hazardous solid waste. In 2014, North Carolina enacted CAMA, which requires that all ash basins in the State be closed, either through excavation or via the cap-in-place method. He explained further that CAMA requires closure of all ash basins in North Carolina, with the closure option (excavate or cap-in-place) and deadline driven by a prioritization risk ranking classification process. Witness Kerin noted that, in many respects, CAMA mirrors the federal CCR Rule. He stated that all of DEC's ash basins must be closed under one or both of these programs. Tr. Vol. 14, pp. 100, 115-26.

He also stated that the Company has begun the process of closing, or submitting plans to close, its ash basins in accordance with the program with the most limiting requirements. Tr. Vol. 14, p. 100. Witness Kerin also testified that coal-powered electric generation has since ceased at four of the eight coal-fired DEC generating facilities with ash basins, including the Dan River, Buck, Riverbend, and W.S. Lee plants. Id. at 103.

Witness Kerin also noted that in addition to the CCR Rule and CAMA, DEC is also subject to other CCR-related obligations that result from state environmental regulatory oversight under existing rules and regulations. For DEC, in South Carolina, there is one Consent Agreement with the South Carolina Department of Health and Environment (SCDHEC) applicable to ash management at the W.S. Lee plant. The W.S. Lee Consent Agreement, between DEC and SCDHEC, requires ash excavation of the Inactive Ash Basin, the Ash Fill Area, and any other areas where ash may have potentially migrated from these sites. Tr. Vol. 14, p. 127.

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Witness Kerin testified that the CCR Compliance Requirements—CAMA, the CCR Rule, and other consent and/or settlement agreements and orders concerning CCR management and disposal—represent new regulatory requirements that have significantly changed the operation and life cycle of the on-site ash basins and landfills. Id. at 115. He noted that there is a great deal of duplication and interaction between federal rule, state law and agency action and that many of the actions Duke Energy will take will serve multiple compliance purposes. He explained that many actions and draft rules applicable to many utilities, not just Duke Energy, were already being developed prior to 2014, and that the Company is now in another wave of evolution in environmental regulation pertaining to ash. He stated that in response to these new requirements addressing CCR disposal activities, the Company is adding dry fly ash, bottom ash, and FGD blowdown handling systems to operating coal-fired plants that are not already so equipped. He also stated that the Company is modifying all active and decommissioned plants to divert storm water and low-volume wastewater away from the basins. He testified that, accordingly, the Company is requesting recovery of the incremental compliance costs related to coal ash pond closures incurred starting in 2015 through November 30, 2017, and recovery of ongoing compliance costs. He maintained that both these incurred and ongoing compliance costs are reasonable, prudent, and cost effective given the individual facts and circumstances at each power plant and ash basin site at issue. He maintained further that each of the Company's historical and ongoing CCR compliance costs is reasonable, prudent, and cost effective given the individual facts and circumstances at each power plant and ash basin site at issue. Tr. Vol. 14, pp. 100-01.

Witness Kerin stated that ash removal has been initiated at several DEC stations, including the Dan River and Riverbend Plants. He stated that excavation plans were developed to systematically prepare for executing this work, including the identification of any necessary permits and approvals. These excavation plans were submitted to the applicable state regulatory body, SCDHEC or DEQ, prior to beginning ash excavations. As the CCR Rule and CAMA lead to ash basin closure, preparations are required to transition the coal-fired generating sites for this outcome. Operating coal-fired power plants in the Carolinas require plant modifications to fully transition to dry ash handling in order to cease sluice flow to the ash basins. All coal-fired power plants, even those retired, require some level of modification to cease all flows to the ash basins, such as storm water or low volume waste water, and may require construction of a new retention pond. These modification activities are planned and are now being executed. Tr. Vol. 14, p. 132.

Witness Kerin described the closure plans and site analysis and removal plans developed by Duke Energy to physically close the ash basins, noting that these plans are technically informed by the structural stability of the impoundments, the potential for adverse impacts from external events such as 100-year floods, the groundwater and/or surface water impacts identified in the Closure Study Analysis, and the groundwater corrective actions required in the Corrective Action Plans. Ash basins can be closed by excavation, with the ash permanently stored in a CCR landfill or used in a beneficial way such as a structural fill or for cementitious purposes. Ash basins can also be closed by capping the CCR in place. Tr. Vol. 14, pp. 132-33.

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Witness Kerin also maintained that the Company's CAMA closure plans will meet the national standards set forth by the CCR Rule as well as the more specific requirements determined by the North Carolina Department of Environmental Quality (DEQ) under the CAMA regulatory process. He explained that the state-mandated closure plans are reviewed and approved by SCDHEC in South Carolina and DEQ in North Carolina. During this review and approval process, these state regulatory agencies could impose additional restrictions, limitations, requirements, and/or actions to close the ash basins. Other specific compliance plans will be developed and implemented to meet the various requirements and timelines of CAMA and the CCR Rule, such as the fugitive dust control plans, which were required under Section 257.80 of the CCR Rule by October 19, 2015. As a second example, run-on and run-off control system plans were developed and implemented by October 19, 2016, for CCR landfills pursuant to Section 257.81 of the CCR Rule. Compliance plans will continue to be developed and implemented as required by the CCR Rule and CAMA. Tr. Vol. 14, p. 133.

Company witness Kerin testified that in Exhibits 10 and 11 to his testimony, he broke the ash pond closure costs already incurred or expected to be incurred prior to November 30, 2017, down into their core components and described the plants to which these costs apply. In detailing these costs, he also provided narrative summaries as to why, in his view, these costs were incurred and why the compliance actions which led to those costs were the most reasonable and cost-effective options given the applicable facts and circumstances. He maintained that these exhibits, coupled with the balance of his testimony and exhibits, demonstrate that these costs are reasonable and prudent. Tr. Vol. 14, p. 135.

Company witness Kerin maintained that DEC's historical handling of CCRs was reasonable, prudent, and consistent with industry standards over time. This demonstrates that nothing that DEC has done historically is causing the Company to incur any unjustified costs today to comply with post-2015 CCR regulations. Tr. Vol. 14, p. 135. Company witness Kerin explained that, in the preamble to the CCR Rule, EPA details that in 2012 alone, over 470 coal-fired electric generating facilities burned over 800 million tons of coal, generating approximately 110 million tons of CCRs in 47 states and Puerto Rico. In 2012, approximately 40% of the CCRs generated were beneficially used, with the remaining 60% disposed in CCR surface impoundments. Of that 60%, approximately 80% was stored in on-site basins and landfills. Across the United States, CCR disposal currently occurs at over 310 active on-site landfills, averaging over 120 acres in size with an average depth of 40 feet, and at over 375 active on-site surface impoundments. Stated differently, according to witness Kerin, the Company is re-using (selling) and storing CCRs in the same manner and at approximately the same percentages as the coal-fired utility industry's national averages. Duke Energy's practices have been and continue to be consistent with those of the industry. Similar to the industry, DEC has on-site CCR landfills that are actively receiving production fly ash, and some bottom ash, at specific coal-fired generating sites, including the Allen, Belews Creek, Cliffside, and Marshall Plants in the Carolinas. Also similar to the industry, DEC has active ash basins still receiving bottom ash, and some fly ash, at specific coal-fired generating sites, including

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the Allen, Belews Creek, Cliffside, and Marshall Plants in the Carolinas. Witness Kerin maintained that the ash handling practices for ash basins and ash landfills in the Carolinas are consistent with the applicable regulatory requirements that were in effect during the history of these CCR units. Tr. Vol. 14, pp. 113-14.

Witness Kerin also maintained that DEC's CCR storage and handling practices are consistent with the practices of other Duke Energy affiliates and Duke Energy peer utilities. He explained that the Company's CCR storage and handling practices are consistent across the Duke Energy fleet, including coal generation located in Florida and in the Midwest. Duke Energy as it currently exists today has been formed over the years through the mergers of several utilities with independently operated coal fired generation, including the Cinergy Corporation in 2006 and Progress Energy, Inc. in 2012. Indeed, going further back in time, Progress Energy, Inc. was created in 2000 from the merger of legacy utilities CP&L and Florida Power Corporation (FPC). Similarly, Cinergy Corporation was created in 1994 by the merger of legacy utilities Public Service Indiana (PSI) and Cincinnati Gas & Electric Company (CG&E). Yet, the historical and current CCR handling and use of CCR basins is consistent across all of these legacy companies that make up Duke Energy Corporation today, and consistent with the industry. Tr. Vol. 14, p. 114.

At the hearing, in response to questions from counsel for the Sierra Club regarding reports on ash disposal from the 1970s and 1980s, witness Kerin clarified that DEC did not build any new basins after 1982, when the last basin was constructed at Buck, and that any other disposal areas constructed by the Company would have been undertaken pursuant to permit by the DEQ or its predecessor. Tr. Vol. 14, pp. 180-84. He also testified that, in his opinion, there would not be increased cost associated with the schedule of activities contained in the draft Special Order by Consent (SOC) resolving a DEQ Notice of Violation with regard to the Allen, Marshall, and Cliffside plants that would not otherwise have been incurred, and clarified that cap-in-place costs are based on acreage size, not volume of ash in the basin. Id. at 213-18.

In his direct testimony, Company witness Wright noted that coal ash use and disposal has been studied by the EPA since the mid-1980s. After several studies and some limited regulatory standards, on May 22, 2000, the EPA determined the need to regulate coal combustion wastes under Subtitle D of the Resource Conservation and Recovery Act (RCRA). He noted that these types of expenses have been routinely recovered as a cost of service and included in rate cases including the reasonable costs associated with operating, maintaining and upgrading environmental equipment. The cost recovery for these rate-based environmental costs also usually included a return. Tr. Vol. 12, pp. 130-31.

C. Company Direct: Cost Recovery Overview

Witness Wright also testified that in part as a response to an accident at a surface impoundment at Tennessee Valley Authority's (TVA) Kingston Fossil Plant in Harriman, Tennessee, the EPA published in the Federal Register proposed new coal ash disposal

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regulations for CCRs. The proposed regulations specifically referenced the TVA incident as a major reason for the proposed rule, and discussed several other coal ash incidents that led to the promulgation of the rule. Witness Wright maintained that, because the EPA's proposed rule's publication date precedes the February 2, 2014 coal ash release accident at the Dan River Steam Station (Dan River), the Dan River accident was not mentioned in the EPA's proposed rule, nor could it have been, as a reason for establishing the rule. He also noted that EPA's finalized CCR Rule, signed on December 19, 2014 and published in the Federal Register (FR) on April 17, 2015, did reference the Dan River accident, but it did not indicate that the accident modified the proposed rule. Tr. Vol. 12, pp. 131-32.

Witness Wright further explained that in August 2014, after the EPA's proposed coal ash regulations were published but prior to their finalization, the State of North Carolina adopted CAMA. He noted that while EPA and CAMA rules are similar in many respects, "largely duplicative," DEC must ensure that its coal ash disposal methods meet the standards established in both regulations as well as any other state agency requirements. Tr. Vol. 12, p. 132.

Witness Wright maintained that recoverable costs, as they relate to electric utility expenditures in North Carolina, are costs that are reasonable and that are prudently incurred in the provision of safe, reliable electric service to a utility's customers. He argued that N.C. Gen. Stat. § 62-133(b) embodies this principle. He maintained that because environmental compliance costs are a necessary cost of providing electric service, these types of costs – and a return on those costs if deferred over time – are recoverable in rates. He also maintained that environmental compliance costs are similar to other costs that a utility might spend in producing and delivering power. He asserted that the Company incurs costs in compliance with environmental laws and regulations, similar to other costs necessary for the generation of electric power, and that these coal ash disposal costs are like nuclear decommissioning costs or coal plant retirement costs which have long been deemed recoverable for utilities across the country, including DEC. Tr. Vol. 12, p. 123.

Witness Wright noted that the Commission has allowed the recovery of costs related to environmental expenditures. Citing to witness Kerin's lengthy discussion of the numerous investments the Company has made over time in compliance with historical coal ash and other environmental regulations, he asserted that in his experience these types of costs, including the reasonable costs associated with operating, maintaining and upgrading environmental equipment, plus a return, have been routinely recovered as a cost of service through general rate cases, whether as capital or ongoing operation and maintenance expense or some combination thereof. Tr. Vol. 12, pp. 127-29.

Witness Wright testified further that utilities are not allowed to recover environmental fines or penalties, or costs incurred from the actions causing such penalties. He stated his understanding that none have been requested in this case. He also asserted that it is important, however, to make sure that the costs underlying or directly causing such fines or penalties be separated from prudently incurred, ongoing

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costs. For example, he offered, if a generating plant received a fine, that fine should not be recoverable. The fact that a fine was given, however, does not mean that the ongoing, prudently-incurred costs necessary to produce generation should be disallowed. Tr. Vol.12, p. 130.

Witness Wright further asserted that the new federal coal ash standards did not result from the Dan River spill. He noted that the final rule only mentions the Dan River accident, and that there is no clear evidence in the final rule that the Dan River accident changed or modified the EPA's proposed rule. He asserted that both the proposed rule and the final rule addressed the need for imposing corrective action at inactive facilities, and asserted that in promulgating the CCR Rule, the EPA cited hundreds of potential risks or incidents with ash ponds similar to Dan River that, in part, led to the adoption of the Rule. Based on this analysis along with the timing of the CCR Rule, he opined that the Dan River accident did not change the CCR regulations, although it probably added support for the EPA's proposals. Tr. Vol. 12, pp. 132-34.

Witness Wright also maintained that, in terms of timing, the new state CAMA coal ash standards did result from the Dan River spill, but in terms of the substance of the standards adopted there is not necessarily a connection. He opined that the Dan River spill helped prompt the North Carolina General Assembly to examine the State's and national coal ash disposal policies and regulations, and that out of that legislative investigation came CAMA. He noted that some four years prior to Dan River, the EPA had proposed and was close to finalizing its new CCR regulations, which in his opinion helped inform the State's legislative leaders regarding the language contained in CAMA. He noted that the proposed CCR regulation also strongly encouraged the states to adopt at least the federal minimum criteria in their solid waste management plans. Therefore, he concluded, that the North Carolina Legislature and/or the State's DEQ would likely have taken steps to adopt coal ash regulations shortly after the CCR Rule was finalized in 2015. He concluded that the timing of CAMA was influenced by the Dan River accident, but also expressed his belief that, even without the Dan River accident, the State would likely have adopted some new coal ash disposal standards similar to CAMA in the 2015 timeframe in response to the CCR rules. He stated that, regardless, the Company must comply with both the federal and state coal ash disposal standards. Tr. Vol. 12, pp. 134-36.

In his direct testimony, Company witness Wright testified that, in his opinion, the coal ash disposal costs that DEC seeks to recover in this case are "used and useful" utility cost. Tr. Vol. 12, p. 144. He explained that DEC's coal ash disposal sites have always been used and useful as part of the coal-fired generation production process. He noted that N.C. Gen. Stat. § 62-133(b)(1) provides that, in setting utility rates, the Commission must "ascertain the reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service rendered to the public within the State, minus accumulated depreciation, and plus the reasonable cost of the investment in construction work in progress." Id. He testified that, therefore, to be recoverable and/or included in rate base, the cost must be both reasonable and incurred for property that is used and useful in providing service to

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customers. He stated that the Company has historically spent dollars in order to comply with the coal ash disposal regulations in effect at the time, and these dollars were a necessary expenditure related to used and useful utility costs made in the provision of electric service at the time. The Company was, and continues to be, obligated to meet the needs of its customers. This obligation to serve requires the disposal of coal ash subject to the disposal standards at the time, thereby rendering the disposal sites for this coal ash, for which costs DEC seeks recovery in this case, "used and useful" in providing electric service. Id. at 144-45. He stated that this is supported by the Commission's conclusions in the 2016 Dominion rate case, where the Commission determined that because current CCR repositories are and have served their purpose of storing CCRs for many years, they have been used and useful for ratepayers, and that such storage facilities will continue to be used and useful until the CCRs are moved to a permanent repository, or they are capped and closed. Id. at 145-46.

Witness Wright also noted with respect to the Commission's Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions in Docket No. E-22, Sub 532 (Dec. 22, 2016) (2016 DNCP Rate Order) that, in that case, the Commission addressed the exact issue of the recovery of coal ash disposal costs that is at issue in this proceeding. In addition to the decision that prior coal ash disposal assets were used and useful, he noted that in that order the Commission and Public Staff concluded that Dominion's historical response to coal ash disposal was consistent with industry practice at the time and that these costs were reasonable and prudent. Second, they found that Dominion's test year coal ash disposal expenses incurred in compliance with the newer coal ash disposal regulations were likewise reasonable and prudent. Finally, he noted that, similar to what DEC is requesting in this rate case, the 2016 DNCP Rate Order also allows Dominion to establish an ARO to defer additional coal ash disposal cost and for the recovery of those costs to be adjudicated in a future proceeding. Tr. Vol. 12, pp. 146-47.

D. The Positions of Intervenor Parties other than the Public Staff

AGO witness Wittliff maintained that the Dan River ash release was largely responsible for the development of CAMA in its present form, which he said accelerated remediation and closures and narrowed the field of removal and closure options. Tr. Vol. 11, pp. 239, 248-50, 272. He claimed that the plea agreements into which the Company has entered evidence harm to the environment caused by DEC's criminal negligence. Id. at 239-41, 265-67, 272-73. He also claimed that the Company's actions and inactions resulted in environmental harm and the incurrence of compliance costs that could have been significantly lower or possibly even avoided. Id. at 274-75. He asserted that, by not building new lined surface impoundments when it was "obvious" that additional impoundments were needed and would better protect the environment, the Company delayed and avoided potential exposure to requirements for more rigorous environmental controls on the new impoundments. Id. at 255. He questioned the Company's diligence with respect to managing dam safety, contended that the Company did not comply with the requirements of its ash basin permits at Dan River and Riverbend, and asserted issues of vegetation control and stability of impoundments at other facilities. Id. at 255-63,

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273-74. He also claimed that the Company's 10-K filings with the Securities and Exchange Commission (SEC) show Duke Energy's awareness of trends in coal ash management and regulation towards lined impoundments. Id. at 236-38. Witness Wittliff further questioned Company witness Kerin's expertise with regard to coal ash issues and claimed that the Company's coal ash handling practices were not consistent with industry. Id. at 268-69.

At the hearing, in response to questions by counsel for the Company, witness Wittliff admitted that, while his testimony stated that he would support a Commission finding that the coal ash costs incurred by DEC were unreasonable and imprudent, his actual position is that the Company should be able to recover its costs to comply with the CCR Rule, but nothing more. Tr. Vol. 11, pp. 279-81. However, in its post hearing brief the AGO, on whose behalf witness Wittliff testified, maintained that all of DEC's 2015-2017 CCR remediation costs should be disallowed. Witness Wittliff stated that costs incurred by the Company to comply with the CCR Rule are reasonable and prudent. Id. at 282-83. He admitted that he did not identify any specific costs that could have been lower or should be disallowed. Id. at pp. 287-89. In response to questions regarding environmental compliance issues at electric power stations at which he had worked over the course of his career, witness Wittliff testified that he was not in a position at those times to say what those companies should or should not have done with respect to environmental compliance, but that he is in such a position now with respect to DEC, to say what should have happened with the Company's previous coal ash management. Tr. Vol. 11, p. 289 – Tr. Vol. 12, pp. 13-24.

CUCA witness O'Donnell opined that DEC should only recover costs to comply with the CCR Rule, not any costs under CAMA that exceed CCR Rule compliance costs, based on his contention that Duke Energy caused CAMA. Tr. Vol. 18, pp. 59-60. Witness O'Donnell purported to compare the DEC coal ash ARO to what he termed similar coal ash AROs of utilities across the United States. He concluded that the Company's ARO coal ash costs are among the highest in the nation, and contended that the only discernable difference between the Duke Utilities and the other utilities in his comparison was CAMA, which he asserted was prompted by the Dan River spill. He stated that DEC did not provide a similar financial analysis for this case. Id. at 56, 61-66. He asserted that there is no evidence to suggest that Duke's coal ash situation is significantly different from that of utilities across the country or from that of utilities in neighboring states. He claimed the Company failed to provide any evidence to counter his argument that its mismanagement led to excessive costs associated with its coal ash cleanup, and that because the Company chose not to dissect his analysis "bit by bit," that gives his evidence more credence. Id. at 66.

Sierra Club witness Quarles evaluated the methods DEC has proposed to close existing coal ash ponds at the Allen and Marshall plants and opined as to environmental conditions that may be associated with capping those ponds in place. He asserted that he evaluated site conditions at each location and the likelihood that DEC will be able to meet closure performance standards in the CCR Rule if it opts for cap-in-place closure. He also asserted that continued storage of coal ash at Allen and Marshall poses

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significant environmental risks. He stated that the coal-fired power plant industry recognized in at least the mid-1970s that disposal of CCRs into unlined disposal units and within close proximity to groundwater was risky, and that construction of unlined disposal units after that time was unreasonable. He claimed it would have been consistent with industry practice at the time for DEC to close and remediate leaking impoundments and construct new, lined dry landfills. He asserted that the Company built new unlined disposal areas at Allen and Marshall, and that lined landfills and surface impoundments were commonplace and more cost effective than building unlined surface impoundments since the mid-1970s. Tr. Vol. 6, pp. 19-118, 120-22.

Witness Quarles stated that the unlined basins at these plants were constructed over named and unnamed stream valleys, with wastes submerged in groundwater, and groundwater flows into those basins from topographically higher elevations and will come in contact with submerged coal ash. He also stated that there are documented impacts to groundwater at these basins and that a cap will not prevent lateral inflow of groundwater from adjacent areas. He concluded that closure in place at these basins would allow continued contamination of downgradient groundwater and violate the technical standards of the CCR Rule, and that removal of coal ash from the Company's ash basins would reduce the concentrations and extent of this contamination. Lastly, witness Quarles stated that DEC's plan for closure-in-place is well documented by the coal power trade industry association as an inappropriate groundwater corrective action where CCRs are submerged in groundwater like at Allen and Marshall. Tr. Vol. 6, pp. 19-118, 122-24.

At the hearing, Witness Quarles did not dispute on cross examination by Company counsel that the 1988 Report to Congress stated that only about 25% of all facilities had liners to reduce offsite mitigation of leachate, that only 40% of generating units built since 1975 had liners, that only 15% had leachate collection systems, only one-third had groundwater monitoring systems and that such systems were more common at newer facilities, that coal combustion waste streams generally do not exhibit hazardous characteristics, and that EPA's tentative conclusion was that current waste management practices appear to be adequate for protecting human health and the environment. Witness Quarles also confirmed that he did not conduct a site-by-site engineering analysis of the cost to the Company to close and remediate leaking impoundments and construct new, lined dry landfills. Tr. Vol. 6, pp. 143-45. In response to questions by the Commission he admitted that he has not raised the concerns he raised in this proceeding regarding cap-in-place at Allen and Marshall with DEQ. Tr. Vol. 6, pp. 149-50.

In its post-hearing Brief, the AGO contends that ratepayers should not be forced to cover costs caused by DEC's historic imprudence in managing its coal ash basins. The AGO argues that the Commission needs to consider several factors when determining whether the costs incurred are recoverable in rates. The AGO outlines them as follows: 1- The first is DEC's history of imprudence; 2- DEC's costs must be reviewed in detail to evaluate whether and to what extent they are for property that is "used and useful" and are recoverable in ratebase; 3- DEC has insurance to cover a large portion of the coal ash remediation costs it seeks from ratepayers, and these insurance proceeds should be taken into account; 4- DEC's request for cost recovery relies on a petition for an

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accounting order allowing deferral of the costs that is untimely, unreasonable, and unjustified as a basis for retroactive recovery of expenditures that DEC incurred in 2015 and 2016; and 5- DEC's claim that it is "entitled" to the recovery of coal ash costs from prior periods if it proves the costs are "known and measureable," "reasonable and prudent," and "used and useful" is not consistent with the statutory ratemaking regime, in which rates are established and become effective prospectively in order to allow—but not guarantee—the opportunity for cost recovery, and the rates are presumed to be just and reasonable until new rates are established by the Commission.

The AGO disagrees with this Commission using a 1988 DEP case in its recent decision in Docket No. E-2 Sub 1142, regarding Duke's burden of proof of prudent and reasonable costs. The AGO states that under the Commission's "prudence framework" in the DEP Order recently issued, a utility's costs are presumed to be reasonable and prudent unless challenged, and the challenges presented must show three things: "(1) they must identify specific and discrete instances of imprudence; (2) demonstrate the existence of prudent alternatives; and (3) quantify the effects by calculating imprudently incurred costs." In re Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service In North Carolina, Docket No. E-2, Sub 1142, Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, at 196 (Feb. 23, 2018)("2018 DEP Order")(citing the 1988 DEP Rate Order at 15) The AGO contends that this framework essentially puts the burden of proof on Intervenors. The AGO argues that it should be up to DEC to prove that some or all of the detailed costs are not attributable to its poor history of operations.

The AGO argues that evidence that the Company was noncompliant with regulatory requirements shows its imprudence, and cites Commissioner Brown-Bland's dissent to the 2018 DEP Order, indicating that violations of statutes that have the purpose of protecting the public from harm to life or safety constitute negligence per se. See Bell v. Page, 271 N.C. 396, 156 S.E.2d 711 (1967); Hampton v. Spindale, 210 N.C. 546, 187 S.E. 775 (1936). The AGO contends that DEC's five criminal convictions should be conclusive evidence of imprudence.

The AGO states that the Commission may consider an agency's standards or determinations when making its own determination about the prudence and reasonableness of coal ash activities, but cannot simply substitute another agency's determination or standards for its own. See State ex rel. Utils. Comm'n v. Carolina Water Service of North Carolina v. Public Staff, 335 N.C. 493, 503, 439 S.E.2d 127, 132 (1994).

The AGO states that coal has been utilized for many decades and beginning in approximately 1950, DEC, like many utilities, used unlined earthen impoundments to deposit its CCRs. The AGO states that in the 1970s, the United States Department of Energy directed that research be done on coal ash residuals and that the research revealed that there was a "growing awareness that the discarded wastes from coal combustion are a serious potential source of surface and ground water contamination" and that the wastes "have the potential for causing great environmental damage if not properly handled." 1979 Los Alamos Report, Tr. Ex. Vol. 12, pp. 189-204. In 1988, the

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EPA, in its Report to Congress on the topic of "Wastes from the Combustion of Coal by Electric Utility Power Plants," voiced concerns over the "substantial quantities of wastes" produced by electric utility power plants and concurred with the Los Alamos Report that "[t]he primary concern regarding the disposal of wastes from coal-fired power plants is the potential for waste leachate to cause ground-water contamination" from the potentially toxic metals in the ash due to the fact that "[m]ost utility waste management facilities were not designed to provide a high level of protection against leaching." 1988 EPA Report to Congress, Tr. Ex. Vol. 12, p. 228.

The AGO contends that before the North Carolina General Assembly passed CAMA, DEC's coal ash activities were governed by three important laws: North Carolina's Dam Safety Act, the federal Clean Water Act, and North Carolina's 2L Groundwater rules and that DEC violated all of these laws and standards.

First, the AGO alleges that DEC violated dam safety standards. The AGO states that during the five-year dam safety inspections between 1996 and 2009, all seven of the facilities were cited for issues regarding seeps. Tr. Vol. 11, p. 259. Between 1996 and 2009, the five-year dam safety inspectors also expressed concerns regarding stability issues at the Allen, Dan River, Marshall, Cliffside, and Riverbend Steam Stations. Tr. Vol. 11, pp. 261-262. After the TVA incident, the dams at these facilities were all rated by the EPA in 2009 as having either high hazard potential or significant hazard potential.

Second, the AGO alleges that DEC violated the Clean Water Act citing, among others, that in 2015, Duke pled guilty to five counts of criminally negligent violations of the Clean Water Act. In addition to the four charges involving Dan River, one charge stemmed from the unauthorized discharge of pollutants from an unpermitted channel that allowed contaminated water from its coal ash basin at its Riverbend Steam Station to be discharged into the Catawba River from at least November 8, 2012 through December 30, 2014. Ex. Vol. 12 pp. 355-356, 400-01; Ex. Vol. 12, pp. 302, 346-347. The AGO also cites that after the Southern Environmental Law Center threatened to filed civil lawsuits, DEQ initiated lawsuits against all of the Company's facilities which was resolved by the parties. The AGO also cites that on March 4, 2016, the DEQ issued Notices of Violation to Duke Energy Carolinas related to seeps. Tr. Vol. 11, p. 267. On January 8, 2018, the Company announced its entry into a proposed Special Order by Consent with DEQ to settle alleged water quality violations at the Allen, Marshall, and Cliffside Steam Stations. Id. Each of the seeps identified and addressed in the Special Order exhibited some indication of the presence of coal ash wastewater. Id. The Company paid $84,000 ($4,000 each for 21 seeps identified at these facilities prior to January 1, 2015) and committed to dewatering six coal ash ponds at these three facilities. Id. The resolution of these seeps is independent of the requirements of the CCR Rule and CAMA, and therefore any activities employed to resolve these seeps should be disallowed. Id.

Third, the AGO claims that DEC violated the 2L groundwater standards citing that in 2012 and 2013, when all of Duke's sites were monitored and the groundwater data gathered, the Company found and the EPA noted that there were exceedances of the groundwater 2L standards at all eight sites. 40 CFR Parts 257 and 261, 80 Fed. Reg. 74

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(Apr. 17, 2015), p. 21455; AGO Late-Filed Exhibit 1-K-Nov. 4, 2013 Ash Basin Groundwater Summaries. The AGO provides that the Company gave notice of potential legal claims arising from groundwater contamination to its insurers in 1996 and 1997. In that correspondence, Duke advised its insurance carriers, AEGIS and Lloyd's of London, that it may have legal exposure for pollutant discharges from coal combustion residuals ponds at its coal-fired power stations. Ex. Vol. 10, p. 528; Ex. Vol. 10, p. 538. The AGO further states that on November 3, 2013, Duke Energy Corporation prepared a breakdown of data regarding exceedances of the 2L water quality standards for all of its facilities and found exceedances at all eight of the Company's plants. AGO Late-Filed Exhibit 1-K- "Nov. 4, 2013 Ash Basin Groundwater Summaries" Duke_USAO_01448182. Significantly, Allen Steam Station, Buck Steam Station, Dan River Steam Station, and W.S. Lee Steam Station had exceedances of both the primary and the secondary standards. Lastly, in its settlement of the 2013 court case, DEC agreed to perform groundwater remediation per CAMA and 2L. The AGO argues that CAMA only applies to surface impoundments, not inactive ash areas, N.C.G.S. 130A-309-200 et seq. (2017); therefore, any costs associated with the excavation and removal of inactive ash areas are patently related only to the Company's violation of groundwater regulations and should be disallowed.

The AGO further argues that DEC disregarded the law citing that Mr. Wells testified that "there was no obligation in the 2L rules to monitor groundwater quality" after the corrective action requirements were added, and in fact, the Company considered itself "under no universal obligation to monitor for groundwater impacts" until required to do so via a NPDES permit or other regulatory requirement mandated by the regulatory agency. Tr. Vol. 24, pp. 229-230. The AGO argues that the 2L Rules, since their promulgation in 1979, are and have always been founded on strict liability and self-enforcement principles. 15A N.C.A.C. 02L .0101 et seq. As stated in its Policy provisions, "[n]o person shall conduct or cause to be conducted, any activity which causes the concentration of any substance to exceed" the water quality standards specified in these Rules. 15A N.C.A.C. 02L .0103(d) (2017). As these Rules "are applicable to all activities or actions, intentional or accidental, which contribute to the degradation of groundwater quality," DEC had a duty to comply with these Rules. Id.

Next, the AGO argues that DEC understood the changing regulatory landscape for years and did not change its practices. The AGO cites many documents that prove this point. The AGO contends that as early as 2003, more than ten years prior to the enactment of CAMA and the Federal CCR Rule, DEC knew that at some point in the future, it would no longer be able to store wet ash in unlined surface impoundments but did nothing about it. Ex. Vol. 16, Pt. 2, p. 123. In January 2007, DEC noted that it would "be required to construct landfills for disposal of its non-saleable CCP . . . in the years to come …" Ex. Vol. 16, Pt. 3, p. 50. In a document called "Duke Energy Environmental Management Program for Coal Combustion Products" dated May 29, 2007, Duke called "disposal in surface impoundments" the highest risk method of disposition of coal ash, and stated that this risk assessment should be used to support planning and management decisions. Ex. Vol. 16, Pt. 3, p. 60. In its 2010 Securities and Exchange 10-K filing, Duke Energy Corporation advised that it currently estimated that it would spend $131 million

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"over the period 2011-2015 to install synthetic caps and liners at existing and new CCP landfills and to convert some of its CCP handling systems from wet to dry systems to comply with current regulations." Ex. Vol. 16, Pt. 3, p. 238. Other documents include a 2013 Ash Basin Closure Strategy (AGO Late-Filed Exhibit 1-E-"Ash Basin Closure Strategy" p. Duke_USAO_01448357), review notes of an Environmental Review given to the Board of Directors of Duke Energy Corporation on August 27, 2013, (AGO Late-filed Exhibit 1-I.), and a presentation made to the Senior Management Committee on the "Ash Basin Closure Strategy on November 25, 2013. AGO Late-Filed Ex. 1-L p. Duke_USAO_1329810. The AGO states that in January 2014, less than a month before the Dan River spill, Duke Energy Corporation's Senior Vice President of Environmental Health and Safety acknowledged in a presentation to the Senior Management Committee that the Company's "coal ash is impacting the groundwater at all locations [and that] [t]his is not an overnight event, ash has been managed in this fashion for decades and it will take decades to close the ponds." Ex. Vol. 10, p. 611. Two of the recommendations given to the Senior Management Committee were to 1) "aggressively pursue closure of ash ponds at all decommissioned sites" and 2) "close all active ash ponds." Id. at 659. The AGO argues that despite the need to pursue the closure of its ash ponds and to convert to dry ash handling, DEC never implemented its own internal recommendations prior to the Dan River spill and the enactment of CAMA and the Final CCR Rule.

Next, the AGO argues that DEC failed to meet industry standards as it failed its duty to be a reasonable and prudent operator. The AGO further argues that under any standard, the Intervenors have shown the costs are not reasonable for cost recovery. The AGO states that it has shown discrete instances of imprudence, that prudent alternatives existed, and that imprudently incurred costs are enormous and certain disallowances should be made by the Commission. The AGO further argues that the Commission may "not allow an electric public utility to recover from the retail electric customers of the State costs resulting from an unlawful discharge to the surface waters of the State from a coal combustion residuals surface impoundment." N.C. Gen. Stat. § 62-133.13 (2014). This section of CAMA applies to discharges occurring on or after January 1, 2014. N.C.G.S. Session Law 2014-122, Sen. Bill 729, Part I, § (1)(b). The AGO states that it is not possible to determine exact disallowances, but the AGO contends that there are costs that would have resulted from the unlawful discharges to the surface waters of the State from at least the Riverbend plant cited in the Federal criminal case from January 1, 2014 to December 30, 2014. Ex. Vol. 12, pp. 400-401.

Next, the AGO submits that DEC should not receive "carrying costs" during amortization of the deferred CCR costs by placing the unamortized balance in rate base because the deferred CCR costs are not used and useful but rather are special operating expenses. According to the AGO, operating expenses are recoverable without return pursuant to N.C. Gen. Stat. § 62-133(b)(3) and State ex rel. Utils. Comm'n v. Thornburg (Thornburg I), 325 N.C. 463, 475, 385 S.E.2d 451, 458 (1989). Further, the AGO submits that the unamortized balance of the CCR deferred costs are similar to those considered in State ex rel. Utils. Comm'n. v. Carolina Water, 335 N.C. 493, 507, 439 S.E.2d 127, 135 (1994) (Carolina Water), where the Supreme Court considered whether the Commission erred when it treated utility plant that was not in service at the end of the test year – and

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would not be returned to service – as "an extraordinary property retirement," allowed amortization of the unrecoverable costs over ten years, and included the unamortized portion in rate base. The Court concluded that the costs were for plant that was not used or useful and, thus, the unamortized costs should not have been included in rate base. As the Supreme Court explained: "Including [these] costs in rate base allows the company to earn a return on its investment at the expense of the ratepayers." Id. at 508, 439 S.E.2d at 135.

Further, the AGO contends that the coal ash activities and expenditures are no longer related to ongoing or active property used or useful for providing utility service. The AGO states as support for this position that the costs in the asset retirement obligation are for the closure of basins and disposal of coal ash that Duke has identified with retired coal-fired steam stations (Ex. Vol. 16, Pt. 1, p. 24); the AGO argues that these coal ash closure and disposal costs are typically recovered in depreciation expense for long-term assets, as is recognized in the Commission's 2003 Order on Asset Retirement Obligations, DEC's internal evaluation of coal ash in 2014 contemplated the use of depreciation reserve funds, and Duke response to questions about whether such costs are included in depreciation expense in which DEC stated that the costs were not thought to result in a net negative salvage value, not that depreciation is inapplicable to such costs (Ex. Vol. 10, p. 691); depreciation costs are recovered over the 'useful life' of the asset. The AGO argues that no attempt has been made to define a useful life for the "property" that has generated coal ash expenditures and the retired plants where most of the costs were incurred do not have a remaining 'useful life' and no attempt has been made to identify the cost components, or consider the distinction between expenditures at operating versus retired plants or between expenditures such as those for construction of a landfill versus transportation costs.

The AGO posits that the fact that Duke has created an Asset Retirement Obligation for the coal ash expenditures does not dictate how the Commission must treat the costs for regulatory purposes. Deferral accounting is used to keep the regulatory accounting the same until a change in regulatory accounting is authorized. The AGO argues that imposing these coal ash costs on current ratepayers raises intergenerational fairness given DEC's failure to take action earlier. The AGO highlights that the Commission has previously dealt with the intergenerational issue when it considered whether to allow the recovery of manufactured gas plant clean-up costs based upon new environmental requirements. The AGO states that the Commission allowed recovery of the clean-up costs, however the amount was amortized over a period of years and no carrying costs were allowed on the unamortized balance.

The AGO contends that DEC's request to recover the deferred costs involves single-issue ratemaking, i.e., Duke seeks to recover coal ash costs going back to the beginning of 2015 – plus carrying costs – without review of the other rate elements that were in effect in 2015 that might offset the need for the cost recovery. With respect to the ARO, the AGO contends that DEC failed to request authorization to defer the coal ash costs before they were incurred and that the deferral in this case relates to Duke's establishment of an Asset Retirement Obligation for costs that are already accounted for

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in rates through amortization and depreciation. Lastly, the AGO argues that Duke's proposal to recover $201 million per year for ongoing coal ash costs as regular operating expenses is unreasonable and should be denied. Instead, Duke should be authorized to defer future costs for recovery in a future general rate case.

In its post-hearing Brief, CUCA contends that DEC's request for 100% CAMA compliance cost recovery is not appropriate. CUCA submits that DEC's costs are overstated and that many are the result of DEC's negligence, which is most clearly highlighted in DEC's guilty plea in the federal criminal environmental proceeding. CUCA supports an equitable sharing of the CCR cleanup costs due to the fact that CAMA costs are much higher than the CCR Rule compliance costs and that DEC's mismanagement directly led to the passage of CAMA. CUCA states that a 25% recovery is equitable. Further, CUCA contends that the CCR Rule is a self-implementing rule which has not been triggered by any citizen suits, and that in the absence of a regulatory directive to do so, DEC should not have pursued regulatory closure of operating sites. CUCA asks the Commission to revisit its analysis of management penalty in the DEP rate case order stating that the $30 million penalty amounts to a 1%[55] penalty which is too low based upon the evidence of DEC's negligence and criminal acts to come to a more fair result in this case. CUCA contends this division of costs sends the message that DEC is not being held responsible for its actions. Lastly, if the Commission does allow a similar 1% penalty in this case, it should also decrease the return on equity as DEC becomes a less risky company.

In its post-hearing Brief, CIGFUR III argues that DEC should not be allowed an equity component in the calculation of its deferred coal ash remediation carrying costs and that the appropriate amortization period is ten to fifteen years as opposed to five. CIGFUR III states that the total cost to defer is $497 million and that the carrying charges associated with the incurred coal ash costs since 2015 are $27 million, $6 million is associated with the cost of debt and $21 million is associated with the cost of equity. CIGFUR III further states that amortizing over 5 years results in annual amortization expense of $104.8 million, plus a $29.9 million net tax return, for a total requested revenue requirement of $135 million for deferred coal ash pond closure costs. CIGFUR III argues that the carrying costs should not include the equity component and that the deferral should be financed at the lowest option, which is the cost of debt. Allowing the equity component increases the amount charged to DEC's ratepayers and is inappropriate for such a significant expense that fails to enhance reliable service. CIGFUR III submits that the CCR costs were incurred over many decades and the stored coal ash is no longer used and useful in the provision of electric service. With respect to the run rate, CIGFUR III argues that DEC should not recover the run rate of $201 million and that DEC should defer ongoing costs for future recovery in its next rate case.

Sierra Club, in its post-hearing Brief, first discusses the legal standard for setting just and reasonable rates. Sierra Club argues that the closure of DEC's CCR basins is

[55] One percent relates to the penalty amount in relation to the Company's total CCR expenditures to comply with CAMA and the CCR rule, including future expenditures. Further, in relation to the DEP case, the 1% does not include the approximately $10 million discrete disallowance for transportation costs.

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not in direct response to the CCR Rule or CAMA, but was made necessary because of DEC's unlawful discharges of CCR constituents to surface waters, and, therefore, DEC's closure costs are not recoverable under N.C. Gen. Stat. § 62-133.13. Further, Sierra Club contends that all of DEC's CCR basins are unlawfully discharging pollutants into surface waters and/or groundwaters, and that the only way to stop these unlawful discharges is to close the ponds and eliminate the source, the coal ash. Therefore, Sierra Club concludes that the cost of pond closures results from the unlawful discharges and are not recoverable.

Sierra Club submits that DEC failed to meet its burden to prove that storage of CCRs in unlined, leaking basins for decades was a reasonable and prudent way for DEC to manage its CCRs. According to Sierra Club, the DEC evidence provided by witnesses Kerin, Wells and Wright about the historical handling of CCRs being reasonable, prudent and consistent with industry standards over time is not credible. Rather, Sierra Club contends that: (1) DEC's groundwater monitoring did not comply with the EPRI standards set forth in EPRI's CCR manuals; (2) that DEC's continued use of unlined basins was contrary to the national trend toward lined basins or dry fly ash handling systems; and (3) that DEC's response to the surface water and groundwater pollution shown by its monitoring reports, once it finally began monitoring, was not reasonable or adequate. Sierra Club states that DEC's first facility to be converted to dry fly ash handling was the Belews Creek plant in 1983, after DEC became aware that selenium from sluiced coal ash was killing the fish in Belews Lake. The result, according to Sierra Club, was a 75% decrease in selenium concentrations.[56] Yet DEC did not use this information and experience to perform investigations at other plants, or to convert to dry fly ash handling at other plants.

Sierra Club also cites DEC's criminal pleas as evidence that DEC allowed unauthorized discharges of pollutants into surface waters. Sierra Club states that the environmental audits conducted as a part of DEC's plea arrangement identified unauthorized seeps containing pollutants above background levels at all DEC plants. Sierra Club contends that the evidence these unauthorized discharges of pollutants have been occurring for an undisclosed amount of time, and, pursuant to N.C. Gen. Stat. § 62-133.13, provide the basis for the Commission to deny all costs of dewatering the CCR basins, at a minimum.

With regard to groundwater pollution, Sierra Club states that DEC failed to follow the industry standard for monitoring compliance with the 2L requirements and, instead, conducted initial sampling at the Allen plant, then extrapolated that data to conclude that there was no violation of the 2L standards at DEC's other seven plants. Sierra Club contends that DEC did not conduct consistent groundwater monitoring at all of its plants until the 2000s, and that similar to the surface water audits the court ordered ground water audits found that CCR constituents are in the groundwater beneath all of DEC's CCR basins. In addition, Sierra Club points to DEC's 1996 insurance letter as proof that DEC

[56] The selenium levels of concern at this site were from water discharges allowed from the NPDES permit rather than from groundwater leachate.

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knew about contamination above the 2L standards at Allen, Belews Creek, Dan River, Marshall and W.S. Lee as early as 1996.

Sierra Club submits that the manner in which DEC failed to inspect and maintain the Dan River basin is indicative of its history of mismanagement and inaction with respect to CCR, and that this is conclusive evidence of imprudence, along with the following decisions made by DEC during the last 30 years:

(1) Failing to follow industry standards to stop using unlined basins.
(2) Waiting 20 years after the fish kill at Belews Creek to convert other plants to dry fly ash handling.
(3) Not conducting preliminary site investigations at all plants after the fish kill at Belews Creek.
(4) Waiting 30 years to regularly monitor ground water, contrary to the industry standard as of 1981.
(5) Not taking any action in response to the 1981 or 1982 EPRI manuals or the 1988 EPA Report, such as switching to lined basins, monitoring groundwater and dewatering basins.
(6) Spending millions of dollars on a leachate collection system at Allen and Marshall, then dumping the leachate into unlined basins at Allen and Marshall.

Moreover, Sierra Club argues that DEP's closure plans for its Allen and Marshall CCR basins do not comply with the CCR Rule or protect against continued discharges, and, therefore, DEC's proposed run rate should be rejected. Sierra Club contends that capping in place the Allen and Marshall CCR basins will not protect against continued contamination of ground water due to leaching of coal ash constituents into groundwater or into surface waters through migration.

NC WARN contends that DEC should not be allowed to recover any costs for the mitigation and cleanup of its CCR basins based on its extensive managerial mistakes and failures to take prompt action to correct known liabilities, and that no CCR costs should be borne by ratepayers. According to NC WARN, DEC has not met its burden of showing which of its CCR costs are capital expenses and which are operating expenses, N.C. Gen. Stat. § 62-133(b)(1) limits rate base recovery in rates to "property used and useful," and the statute does not include operating costs. As such, DEC's costs of compliance with federal and state directives stemming from CCR violations, and court orders mandating cleanup cannot be placed in rate base or otherwise recovered.

NC WARN also states that a review of the NC Clean Smokestacks Act is helpful because it provides guidance on what costs should not be allowed, such as costs incurred by the utility for failure to comply with any federal or state law, rule, or regulation for the protection of the environment or public health, and criminal or civil fines and penalties. N.C. Gen. Stat. § 62-133.6(a)(2). NC WARN asserts that the evidence shows that all of the costs incurred by DEC relating to CCR came from court orders and criminal plea agreements, and that DEC took no actions voluntarily, even actions that could have

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minimized subsequent costs and mitigated environmental damage. Further, NC WARN states that the evidence shows that DEC "knew or should have known" about the significant problem of leaking CCR basins in the early to mid-1980s, if not before, and that the industry standard increasingly became lining CCR basins to prevent water contamination. NC WARN points to DEC's insurance letters in 1996, 2011, and 2016 regarding potential damages and future compensation for mitigation and cleanup costs as significant evidence of what DEC knew or should have known, and contends that the refusal by the insurance companies to cover these multi-million dollar claims demonstrates DEC's culpability for at least the last 20 years. In conclusion, NC WARN submits that DEC mishandled its coal ash for decades, taking the least expensive options, and disregarding the substantial negative impacts of coal ash on families, property, and water supplies adjacent to the coal ash basins, and that the evidence demonstrates criminal negligence, millions in fines and penalties, and a number of judicial decisions and regulatory actions requiring DEC to do what it should have done all along.

E. The Position of Public Staff Witnesses Garrett and Moore

Public Staff witnesses Garrett and Moore testified that they investigated the prudence and reasonableness of costs incurred by DEC with respect to its coal ash management. In addition, they reviewed the approach taken by DEC to determine the least cost method of achieving compliance with the laws and regulations governing coal ash management. Witnesses Garrett and Moore testified that in some circumstances, DEC incurred costs associated with management of coal ash from CCR units that were not required under State or federal law. In those circumstances, witnesses Garrett and Moore evaluated the specific facts and details surrounding those CCR units to determine whether they agreed that DEC's management of those CCR units was reasonable and prudent. To the extent they believed that DEC's actions and costs incurred were not reasonable nor prudent, they recommended that the Commission disallow these costs. In conducting their investigation, witnesses Garrett and Moore reviewed the closure plans and coal ash-related costs incurred for all of DEC's coal-fired facilities, conducted extensive discovery, participated in numerous meetings, and visited several of the DEC facilities in question. Tr. Vol. 21, pp. 19-20.

Witnesses Garrett and Moore did not take exception with DEC witness Kerin's general characterization of the applicable federal and State regulations addressing the management and closure of coal ash basins in North Carolina and South Carolina. They did, however, identify several decisions made by DEC they maintained that were not required by law or where lower-cost compliance options were available, which they described in further detail in their testimony. Tr. Vol. 21, pp. 20; 50.

With regard to DEC's Allen, Belews Creek, Buck, Cliffside, and Marshall plants, witness Moore noted that DEQ issued final classifications for these facilities as "Low to Intermediate Risk" in May 2016, and that DEP is in the process of establishing the permanent replacement water supplies required under N.C. Gen. Stat. § 130A-309.211(c)(1) and performing the applicable dam safety repair work at these sites. Tr. Vol. 21, p. 54. Upon completion of these tasks within the timeframe

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provided, the impoundments at these facilities will be reclassified as low-risk pursuant to N.C. Gen. Stat. § 130A-309.213(d)(1). He explained that CAMA requires, at a minimum, that the impoundment be dewatered and closed either by excavation or by placement of a cap system that is designed to minimize infiltration and erosion. Witness Moore noted that this approach is generally the most cost-effective means for closure of a CCR unit. He also testified that CAMA (S.L. 2016-95) does not require the submission of proposed closure plans for low- and intermediate risk impoundments until December 31, 2019, so DEC has not submitted a Site Analysis and Removal Plan (SARP) to DEQ for any of the Low to Intermediate risk facilities at this time. He maintained, therefore, that a prudence review of the closure plans would be premature, so witness Moore took no exception in the present case to DEC's current proposed closure method for the coal ash basins located at Allen, Belews Creek, Buck, Cliffside, and Marshall. Tr. Vol. 21, pp. 55-57.

Public Staff witness Moore took exception to DEC's closure method for the CCR units located at Buck Steam Station. Duke selected Buck, along with DEP's Cape Fear and H. F. Lee Stations, as the three beneficiation sites pursuant to N.C. Gen. Stat. § 130A-309.216, which required Duke to identify three sites located within the state with ash stored in the impoundments suitable for processing for cementitious purposes. Upon selection of the sites, Duke was required to enter into a binding agreement for the installation and operation of ash beneficiation projects at each site capable of annually processing 300,000 tons of ash to specifications appropriate for cementitious products, with all processed ash to be removed from the impoundments located at the sites. Tr. Vol. 21, pp. 58-61. Witness Moore also noted that the timeframe proposed by DEC for beneficiation of the Intermediate Risk sites extends beyond the closure timeframe called for in Section 3.(a) of S.L. 2016-95 for sites deemed Intermediate Risk, and that N.C. Gen. Stat. § 130A-309.215 provides a variance option for closure deadlines that are found to be in the public interest. Id.

Public Staff witness Moore testified that instead of selecting Buck, Duke should have selected the CCR units located at Weatherspoon as one of the three beneficiation sites as required by N.C. Gen. Stat. § 130A-309.216, where Duke has selected the excavation of CCR and beneficial use option, with contracts in place for the delivery of the coal ash material to facilities in South Carolina for use in the concrete industry. This would have allowed the Buck Station to instead utilize significantly lower cost closure options instead of cementitious beneficiation. CCR units at Buck could have been classified as low risk upon completion of the establishment of permanence replacement water supplies and completion of applicable dam safety repair work, and instead may have been eligible for closure under the "cap-in-place" closure method under CAMA, which would have significantly lowered closure costs for Buck. Tr. Vol. 21, pp. 59-61. Witness Moore therefore recommended that the Commission disallow the $10 million already incurred by DEC for the cementitious beneficiation project at Buck. Tr. Vol. 24, p. 108.

With regard to DEC's selected closure actions at the Dan River Plant, witness Moore took exception with DEC's decision to excavate and transport coal ash from Ash Stack 1 at Dan River off-site to the Maplewood Landfill in Amelia, Virginia. He contended

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that had DEC conducted an adequate assessment of on-site greenfield landfill options at the time it began evaluating off-site disposal options, it would have identified viable on-site disposal options that would have allowed DEC to dispose of all of the ash on-site without having incurred the added expenses associated with the off-site transfer and disposal. Tr. Vol. 21, pp. 62-70.

Witness Moore disputed DEC's position that the moratorium on CCR landfills, which was enacted on September 20, 2014, in Section 5.(a) of S.L. 2014-122, and expired on August 1, 2015, had any impact on DEC's ability to construct an on-site greenfield landfill at Dan River in a timely fashion. He also noted that there were no regulatory obligations related to coal ash management that required removal of CCR materials from Ash Stack 1 as stated by DEC, particularly under the aggressive timeframes required for high-priority sites under CAMA. He evaluated DEC's investigation of on-site landfill options, particularly along the western boundary of the property, and found that DEC had no records documenting any evaluation of the area. With regard to the reasons provided by DEC as to why it did not utilize the area between the combined cycle plant and the western property boundary, Public Staff witness Moore found no valid technical reasons why an adequately sized on-site landfill could not have been located along the western boundary to have handled all of the ash on-site without having to incur the significant costs associated with off-site transportation costs and construction of rail handling equipment. Tr. Vol. 21, pp. 64-66.

As a result of DEC's unnecessary actions to transport ash off-site from the Dan River facility, witness Moore recommended a total disallowance at the Dan River facility of $59.3 million from DEC's coal ash expenditures during this recovery period. Public Staff Moore Exhibit 4.

Witness Moore summarized the coal ash closure approach taken by DEC at its Riverbend facility. Witness Moore testified that CAMA required the excavation of CCR materials from the Primary Ash Basin and the Secondary Ash Basin, but there were no regulatory obligations that required removal of CCR materials from the Ash Stack Area or the Cinder Pit. Witness Moore did not take exception with DEC's plan to remove this additional material, but he did take exception with DEC's decision to utilize the Brickhaven structural fill facility for off-site disposal. Tr. Vol. 21, p. 70, 72. Witness Moore testified that the Brickhaven facility did not present any scheduling advantages or reduce costs, and instead resulted in increased delays and litigation resulting from community opposition to the proposed project. Witness Moore testified that the DEC-owned on-site landfill at the Marshall Facility should have been utilized for the disposal of all ash from Riverbend. Tr. Vol. 21, p. 86.

Witness Moore did, however, take exception to DEC's decision to haul approximately 17,000 tons of CCR material from the Ash Stack Area by truck to the R&B Landfill in Homer, Georgia. Instead, Witness Moore stated that DEC could have utilized the landfill at the Marshall Facility for the CCR material, resulting in shorter hauling distances and lower disposal costs. Witness Moore recommended that the Commission

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disallow the $489,600 premium paid to transport and dispose of the 17,000 tons of CCR material to the R&B Landfill, as opposed to the Marshall Station. Tr. Vol. 21, pp. 72-74.

Public Staff witness Garrett focused his testimony on the activities undertaken by DEC at its W.S. Lee site in South Carolina. Witness Garrett agreed with DEC's decision to utilize an on-site landfill to dispose of the ash material in the Primary Ash Basin and Secondary Ash Basin at W.S. Lee, noting that this approach was consistent with Duke Energy's stated guiding principles and provided a lower cost closure solution compared to an off-site landfill. Tr. Vol. 21, pp. 39-40. Witness Garrett also concurred with DEC's decision to take some actions at the Inactive Ash Basin (IAB) and the Old Ash Fill to mitigate risk associated with long-term environmental issues at the site, but he did not agree with DEC's decision to immediately begin excavation and transportation of ash to the R&B landfill in Homer, Georgia. Witness Garrett instead testified that DEC should have followed the recommendations of its consulting engineers, which recommended repair and maintenance on the IAB berm in 2014, rather than immediate excavation. Witness Garrett further stated that DEC failed to provide a regulatory or technical reason to substantiate immediate removal of the ash from the IAB. Witness Garrett therefore recommended that the Commission disallow approximately $27 million from DEC's request, which is the premium associated with the costs incurred by DEC to transport ash to Homer, Georgia, as opposed to excavating and landfilling on-site. Tr. Vol. 21, pp. 40-41.

Witness Garrett also took exception with DEC's plan to excavate and dispose of the coal ash material contained in the Structural Fill area at W.S. Lee, because the area was developed in accordance with all applicable environmental regulations, is not in close proximity to the Saluda River, has been effectively capped in place, and does not pose any environmental concerns in its present state. Id.

F. Public Staff Witness Junis' Equitable Sharing And Coal Ash Adjustment Testimony

Public Staff witness Junis listed three conceptual options for regulatory treatment of coal ash costs. The first option is to allow full recovery of coal-ash related costs on the grounds that the costs have been reasonably incurred to comply with CAMA and the CCR Rule. Tr. Vol. 26, p. 721. This is essentially the approach recommended by DEC, minus fines, penalties, and other specific costs listed in their federal criminal plea agreement as non-recoverable in rate proceedings. Id. The second option is to disallow recovery of costs to comply with CAMA on the grounds that CAMA is the direct consequence of imprudent DEC environmental violations. Tr. Vol. 26, pp. 721-22. The third option is to disallow the costs incurred to defend and remedy environmental violations, except to the extent that CAMA requirements increased the cost of remediation. Tr. Vol. 26, p. 722. Under this approach, which the Public Staff advocates in theory, disallowances would be based on the costs to remediate environmental violations rather than the costs flowing from CAMA compliance. Id.

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While the Public Staff supports the third option in theory, witness Junis encountered "complicating factors" that led him to modify this preferred regulatory treatment for practical reasons. Id. He observed that, while some environmental violations are clearly due to Company negligence, others fall into a gray zone where they are neither clearly imprudent nor clearly reasonable. Tr. Vol. 26, p. 723. For instance, decisions to place coal ash in unlined impoundments could have been reasonable based on what DEC knew or should have known at the time the basins were constructed some decades in the past. Tr. Vol. 26, pp. 723-24. At the same time, Public Staff witness Junis explained that it can be unreasonable to impose on ratepayers the costs incurred because those impoundments leaked coal ash constituents and contaminated groundwater outside the compliance boundaries, in violation of state environmental laws and regulations. Tr. Vol. 26, p. 724. Witness Junis also noted that calculating the costs of many environmental violations would be too speculative as such calculations would involve estimations based on scenarios that did not occur (e.g., preventing violations through basin construction or modification some decades earlier, or remedying violations if CAMA had not been enacted). Tr. Vol. 26, p. 725.

Due to the complicating factors, witness Junis offered a more practical approach that would exclude certain coal ash costs from recovery in rates as follows:

(1) DEC litigation costs incurred during the test year in cases where there are environmental violations;
(2) costs to remedy environmental violations where the costs exceed what CAMA would have required in the absence of environmental violations;
(3) fines, penalties, and other costs associated with the federal criminal plea agreement involving the Dan River and Riverbend plants, payments to DEQ to settle the assessment of penalties involving the Dan River plant, and the penalty for groundwater violations at DEC and DEP plants including Belews Creek and Sutton;
(4) the adjustments and disallowances recommended by Garrett and Moore to the extent there is no double disallowance for the same item; and
(5) an equitable sharing of the remaining allowed costs of coal ash management through the deferral and amortization approach recommended by Public Staff witness Maness.

Tr. Vol. 26, pp. 727-28.

Witness Junis noted that DEC has removed the costs listed in item (3) above from its rate request. Tr. Vol. 26, p. 728. Thus, the regulatory treatment of those costs is not in dispute. The disallowances recommended by witnesses Garrett and Moore are discussed elsewhere in this order. The remaining cost exclusions listed by witness Junis include litigation-related expenses in cases of environmental violations. In this category, he recommended exclusion of $2,109,406 (total system, not just NC retail, as shown in Boswell Exhibit 1, Schedule 3-1(n), line 1) of test year outside legal fees for litigation of the state enforcement actions filed by DEQ alleging violations at all of DEC's North Carolina plants and, to any extent they have not already been excluded by DEC, for litigation of the penalties assessed by DEQ for violations at the Dan River plant. Tr. Vol.

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26, pp. 730-31. Witness Junis asserted that there is compelling evidence of the environmental violations on which these legal actions were based. Tr. Vol. 26, p. 731. He referenced a number of the exhibits to his testimony detailing DEQ data in support of this assertion. Id.

For the category of costs to remedy environmental violations where the costs exceed what CAMA would have required in the absence of environmental violations, witness Junis identified, to date, $1,288,526 (total system) of expenditures incurred from January 1, 2016, through November 30, 2017, for extraction wells and treatment of groundwater at DEC's Belews Creek plant pursuant to the settlement agreement between DEQ and DEP in the Sutton penalty assessment case. Tr. Vol. 26, pp. 733-34. He took the position that these costs would not have been incurred but for unlawful contamination of groundwater by DEC's Belews Creek ash basins, and that these costs are over and above the lowest reasonable costs of CAMA compliance in the absence of violations. In addition to the costs associated with extraction wells and treatment of groundwater, witness Junis identified $857,350 of expenditures for selenium removal equipment at DEC's Riverbend plant on the grounds that this equipment had not been placed in operation at the time of his testimony. Tr. Vol. 26, p. 734. Witness Junis noted that there could be additional costs in this category in the future. Tr. Vol. 26, p. 732.

The final category for disallowance is based on an "equitable sharing" of all coal ash-related costs not otherwise disallowed. Tr. Vol. 26, p. 738. Witness Junis referred to witness Maness' testimony for description of how the equitable sharing should be implemented and the reasons for it. Id. Witness Junis further testified that "An equitable sharing is particularly appropriate in light of the extent of the Company's failure to prevent environmental contamination from its coal ash impoundments, in violation of state and federal laws." Tr. Vol. 26, p. 738. In support of his opinion, he noted the nature and extent of coal ash environmental problems addressed in the federal criminal plea agreement, unlawful discharges, dam safety deficiencies, and numerous groundwater violations. Tr. Vol. 26, p. 739. He added that the sheer number of legal actions against DEC for coal ash environmental violations, while not evidence of the Company's guilt, is suggestive of the extent of the problem. Tr. Vol. 26, pp. 739-40. Witness Junis asserted that the numerous lawsuits regarding DEC's non-compliance with N.C. Gen. Stat. § 143-215.1 and state groundwater rules would in all probability have led to environmental cleanup costs even if CAMA and the CCR Rule had not been adopted, and that the costs of impoundment closures under CAMA and the CCR Rule overlap what would otherwise have been coal ash cleanup costs under existing state and federal environmental laws and regulations. Tr. Vol. 26, p. 741. Based on DEC's culpability for environmental violations, witness Junis testified that an equitable sharing would be appropriate, whereas it would be unreasonable and unjust to burden ratepayers with all the coal ash-related costs when ratepayers were not culpable for the environmental violations. Tr. Vol. 26, pp. 741-42.

Witness Junis responded to DEC witness Kerin's assertion in his testimony that the EPA's 2015 Effluent Limitations Guidelines (ELG) Rule forced DEC to convert its coal-fired plants to dry ash handling. Tr. Vol. 26, p. 742. Witness Junis noted that