STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1131
DOCKET NO. E-2, SUB 1142
DOCKET NO. E-2, SUB 1103
DOCKET NO. E-2, SUB 1153

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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<tr>
<td>DOCKET NO. E-2, SUB 1131

In the Matter of
Application by Duke Energy Progress, LLC, for Accounting Order to Defer Incremental Storm Damage Expenses

DOCKET NO. E-2, SUB 1142

In the Matter of
Application by Duke Energy Progress, LLC, For Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina

DOCKET NO. E-2, SUB 1103

In the Matter of
Joint Application by Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, for Accounting Order to Defer Environmental Compliance Costs

DOCKET NO. E-2, SUB 1153

In the Matter of
Petition of Duke Energy Progress, LLC, for an Order Approving a Job Retention Rider</td>
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<td>ORDER ACCEPTING STIPULATION, DECIDING CONTESTED ISSUES AND GRANTING PARTIAL RATE INCREASE</td>
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HEARD: Tuesday, September 12, 2017, at 7:00 p.m., Richmond County Courthouse, Courtroom A, 105 W. Franklin Street, Rockingham, North Carolina

Monday, September 25, 2017, at 7:00 p.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Wednesday, September 27, 2017, at 7:00 p.m., Buncombe County Courthouse, Courtroom 1A, 60 Court Plaza, Asheville, North Carolina

Wednesday, October 11, 2017, at 7:00 p.m., Greene County Courthouse, 301 N. Greene Street, Snow Hill, North Carolina

Thursday, October 12, 2017, at 7:00 p.m., New Hanover County Courthouse, 316 Princess Street, Wilmington, North Carolina

Monday, November 27, 2017, 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 Bryan E. Beatty,[1] ToNola D. Brown-Bland, Jerry C. Dockham, James G. Patterson, Lyons Gray, and Daniel G. Clodfelter

APPEARANCES:

For Duke Energy Progress, LLC:

Lawrence B. Somers
Deputy General Counsel
410 South Wilmington Street, NCRH 20
Raleigh, North Carolina 27602

Heather Shirley Smith
Deputy General Counsel
40 West Broad Street, Suite 690
Greenville, South Carolina 29601

Camal O. Robinson, Senior Counsel
Duke Energy Corporation
550 South Tryon Street
Charlotte, North Carolina 28202

John T. Burnett
Deputy General Counsel
Duke Energy Florida
299 1st Avenue N, DEF-151
St. Petersburg, Florida 33701

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[1] Commissioner Bryan E. Beatty's term ended before the Commission issued its decision in this proceeding.

Mary Lynne Grigg
Joan Dinsmore
McGuireWoods, LLP
434 Fayetteville Street, Suite 2600
Raleigh, North Carolina 27601

Robert W. Kaylor
Law Office of Robert W. Kaylor, P.A.
353 East Six Forks Road, Suite 260
Raleigh, North Carolina 27609

Kiran H. Mehta
Troutman Sanders, LLP
301 South College Street, Suite 3400
Charlotte, North Carolina 28202

Brandon F. Marzo
Troutman Sanders, LLP
600 Peachtree Street, NE, Suite 5200
Atlanta, Georgia 30308

For the Using and Consuming Public:

David T. Drooz, Chief Counsel
Tim R. Dodge, Staff Attorney
Dianna W. Downey, Staff Attorney
Lucy E. Edmondson, Staff Attorney
Heather D. Fennell, Staff Attorney
Robert S. Gillam, Staff Attorney
William E. Grantmyre, Staff Attorney
Robert B. Josey, Staff Attorney
Public Staff - North Carolina Utilities Commission (Public Staff)
4326 Mail Service Center
Raleigh, North Carolina 27699

Margaret A. Force, Assistant Attorney General
Teresa L. Townsend, Special Deputy Attorney General
Jennifer T. Harrod, Special Deputy Attorney General
North Carolina Department of Justice
Post Office Box 629
Raleigh, North Carolina 27602

For Carolina Utility Customers Association, Inc. (CUCA):

Robert F. Page
Crisp & Page, PLLC
4010 Barrett Drive, Suite 205
Raleigh, North Carolina 27609

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

John D. Runkle
2121 Damascus Church Road
Chapel Hill, North Carolina 27516

For Carolina Industrial Group for Fair Utility Rates II (CIGFUR):

Ralph McDonald
Warren K. Hicks
Bailey & Dixon, LLP
Post Office Box 1351
Raleigh, North Carolina 27602

For North Carolina Sustainable Energy Association (NCSEA):

Peter H. Ledford, General Counsel
North Carolina Sustainable Energy Association
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

For Fayetteville Public Works Commission (Fayetteville PWC):

James P. West
West Law Offices, P.C.
434 Fayetteville Street, Suite 2325
Raleigh, North Carolina 27601

For Commercial Group:

Glenn C. Raynor
Young Moore and Henderson, P.A.
Post Office Box 31627
Raleigh, North Carolina 27622

Alan R. Jenkins
Jenkins at Law, LLC
2950 Yellowtail Avenue
Marathon, Florida 33050

For North Carolina Electric Membership Corporation (NCEMC):

Richard M. Feathers, Senior Vice President and General Counsel
Michael D. Youth, Associate General Counsel
North Carolina Electric Membership Corporation
Post Office Box 27306
Raleigh, North Carolina 27611

For Environmental Defense Fund (EDF):

Daniel Whittle
Environmental Defense Fund
4000 Westchase Boulevard, Suite 510,
Raleigh, North Carolina 27607

John J. Finnigan, Jr., Senior Counsel
6735 Hidden Hills Drive
Cincinnati, Ohio 45230

For The Kroger Company (Kroger):

Ben M. Royster
Royster and Royster, PLLC
851 Marshall Street
Mount Airy, North Carolina 27030

Kurt J. Boehm
Jody Kyler Cohn
Boehm, Kurtz & Lowry
36 East 7th Street, Suite 1510
Cincinnati, Ohio 45202

For Haywood Electric Membership Corporation (Haywood EMC):

Ralph McDonald
Warren K. Hicks
Bailey & Dixon, LLP
Post Office Box 1351
Raleigh, North Carolina 27602

For Sierra Club:

F. Bryan Brice, Jr.
Matthew D. Quinn
Law Office of F. Bryan Brice, Jr.
127 W. Hargett Street, Suite 600
Raleigh, North Carolina 27601

Bridget M. Lee
Dorothy E. Jaffe
Sierra Club
50 F. Street, NW, Floor 8
Washington, DC 20001

For the United States Department of Defense and All Other Federal Executive Agencies (DoD/FEA):

Paul A. Raaf
Office of the Forscom SJA
4700 Knox Street
Fort Bragg, North Carolina 28310

Kyle J. Smith, General Attorney
United States Army Legal Services Agency
9275 Gunston Road
Fort Belvoir, Virginia 22060

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

Mona Lisa Wallace
John Hughes
Marlowe Rary
Wallace & Graham, P.A.
525 N. Main Street
Salisbury, North Carolina 28144

Catherine Cralle Jones
Law Office of F. Bryan Brice, Jr.
127 West Hargett Street, Suite 600
Raleigh, North Carolina 27601

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

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

For 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):

Gudrun Thompson, Senior Attorney
David L. Neal, Senior Attorney
Nadia Luhr, Associate 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
Smith Moore Leatherwood, LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

BY THE COMMISSION: On May 2, 2017, pursuant to Commission Rule R1-17(a), Duke Energy Progress, LLC (DEP or the Company) filed notice of its intent to file a general rate case application. On June 1, 2017, the Company filed its Application to Adjust Retail Rates and Request for Accounting Order (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, President, DEP; Laura A. Bateman, Director of Rates and Regulatory Planning, DEP; T. Preston Gillespie, Jr., Senior Vice President and Nuclear Chief Operating Officer, Duke Energy Corporation (Duke Energy);[2] Stephen G. De May, Senior Vice President of Tax and Treasurer, Duke Energy Business Services, LLC (DEBS);[3] David L. Doss, Jr., Director of Electric Utilities and Infrastructure Accounting, DEBS; Christopher M. Fallon, Vice President of Duke Energy Renewables and Commercial Portfolio, Duke Energy; Janice Hager, President, Janice Hager Consulting; Robert B. Hevert, Partner, ScottMadden, Inc.; Retha Hunsicker, Vice President of Customer Information Systems - Customer Operations, DEBS; Jon F. Kerin, Vice President of Governance and Operations Support – Coal Combustion Products, DEBS;

[2] DEP is a wholly-owned subsidiary of Duke Energy Corporation. (Tr. Vol. 6, p. 27.)

[3] DEBS provides various administrative and other services to DEP and other affiliated companies of Duke Energy. (Tr. Vol. 8, p. 17.)

Julius A. Wright, Managing Partner, J.A. Wright & Associates, LLC; Kimberly D. McGee, Rates and Regulatory Strategy Manager, DEP and Duke Energy Carolinas, LLC (DEC); Joseph A. Miller, Jr., Vice President of Central Services, DEBS; Robert M. Simpson, III, Director of Grid Improvement Plan Integration for Duke Energy's Regulated Utilities Operations, DEP; and Steven B. Wheeler, Director, Pricing and Regulatory Solutions Director, DEBS.

Petitions to intervene were filed by CUCA on May 9, 2017; CIGFUR and NC WARN on May 12, 2017; NCSEA on May 23, 2017; Fayetteville PWC on June 6, 2017; Commercial Group on June 23, 2017; Charah, LLC, on June 27, 2017, which was withdrawn on July 28, 2017, NCEMC on July 5, 2017; EDF on July 6, 2017; Kroger on July 17, 2017; Piedmont Electric Membership Corporation (Piedmont EMC) on July 18, 2017; Haywood EMC on July 27, 2017; the Sierra Club on July 31, 2017; DoD/FEA on August 11, 2017; Rate-Paying Neighbors on August 23, 2017; NCFB on September 6, 2017; the Towns of Sharpsburg, Stantonsburg, Lucama, and Black Creek (Quad Towns) on September 7, 2017; NC Justice Center on September 15, 2017; NCLM on October 3, 2017; and John Everett on December 7, 2017. Notice of Intervention was filed by the Attorney General on June 6, 2017.

The Commission entered Orders granting the petitions to intervene of CUCA on May 11, 2017; CIGFUR and NC WARN on May 22, 2017; NCSEA on May 25, 2017; Fayetteville PWC on June 7, 2017; Commercial Group on June 26, 2017; NCEMC on July 6, 2017; EDF on July 13, 2017; Kroger on July 20, 2017; Sierra Club and Haywood EMC on August 7, 2017; DoD/FEA on August 15, 2017; Rate-Paying Neighbors on September 1, 2017; NCFB on September 14, 2017; NC Justice Center on September 26, 2017; and NCLM on October 4, 2017.

On August 10, 2017, and October 5, 2017, the Commission entered Orders denying the petitions to intervene of Piedmont EMC and the Quad Towns, respectively, but allowing each to participate as an amicus curiae on the issue of DEP's coal combustion residual (CCR) costs.[4] By Order dated December 20, 2017, the Commission denied John Everett's Motion to Intervene as being untimely.

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

On June 20, 2017, the Commission issued its Order Establishing General Rate Case and Suspending Rates. On June 22, 2017, the Commission issued its Order Scheduling Investigation and Hearings, Establishing Intervention and Testimony Due Dates and Discovery Guidelines, and Requiring Public Notice.

On July 10, 2017, the Commission issued an Order consolidating Docket No. E-2, Sub 1142 with Docket No. E-2, Sub 1131 (DEP's request to defer incremental storm

[4] The terms "CCR" and "coal ash" are used interchangeably in this Order.

damage expenses) and Docket Nos. E-2, Sub 1103 and E-7, Sub 1110 (DEP and DEC's requests to defer environmental compliance costs regarding CCRs), allowing those persons who had been granted intervention in those dockets to fully participate in this proceeding. In addition, on August 29, 2017, the Commission issued an Order consolidating DEP's request to implement a job retention rider filed in Docket No. E-2, Sub 1153 with this general rate proceeding.

On July 12, 2017, the Commission issued its Order Revising Procedural Schedule and Requiring Public Notice, revising the dates for the filing of intervenor and rebuttal testimony and exhibits, as well as the date for the beginning of the hearing to take expert testimony.

On September 15, 2017, the Company filed the supplemental direct testimony and exhibits of Company witness Bateman.

On September 22, 2017, Kroger filed the direct testimony and exhibits of Justin Beiber, Senior Consultant, Energy Strategies, LLC. On October 18, 2017, EDF filed the direct testimony of Paul J. Alvarez, President, Wired Group. On October 19, 2017, DoD/FEA filed the direct testimony and exhibits of Constance T. Cannady, Executive Consultant, NewGen Strategies and Solutions, LLC, and Joseph A. Mancinelli, General Manager, NewGen Strategies and Solutions, LLC. On October 20, 2017, the Public Staff filed the direct testimony and exhibits of Jack L. Floyd, Utilities Engineer, Public Staff Electric Division, Jay B. Lucas, Utilities Engineer, Public Staff Electric Division, James S. McLawhorn, Director, Public Staff Electric Division, Dustin R. Metz, Utilities Engineer, Public Staff Electric Division, Tommy C. Williamson, Jr., Utilities Engineer, Public Staff Electric Division, Scott J. Saillor, Utilities Engineer, Public Staff Electric Division, Michael C. Maness, Director, Public Staff Accounting Division, Darlene P. Peedin, Manager, Electric Section, Public Staff Accounting Division, David C. Parcell, Principal and Senior Economist, Technical Associates, Inc., Roxie McCullar, Consultant, William Dunkel and Associates, Vance F. Moore, President, Garrett and Moore, Inc., and L. Bernard Garrett, Secretary/Treasurer, Garrett and Moore, Inc.; CUCA filed the direct testimony and exhibits of Kevin W. O'Donnell, President, Nova Energy Consultants, Inc.; Fayetteville PWC filed the direct testimony and exhibits of Nancy Heller Hughes, Director, NewGen Strategies and Solutions, LLC; CIGFUR filed the direct testimony and exhibits of Nicholas Phillips, Jr., public utility regulation consultant and a Managing Principal of Brubaker & Associates, Inc.; NC Justice Center filed the direct testimony and exhibits of Jonathan Wallach, Vice President, Resource Insight, Inc., and Satana Deberry, Executive Director, NC Housing Coalition; NCSEA filed the direct testimony and exhibits of Michael Murray, President, Mission:data Coalition, Justin R. Barnes, Director of Research, EQ Research, LLC, and Carolina Golin, Southeast Regulatory Director, Vote Solar; Sierra Club filed the direct testimony and exhibits of Ezra D. Hausman, consultant, Ezra Hausman Consulting, and Mark Quarles, principle scientist and owner, Global Environmental, LLC; NCLM filed the direct testimony of Bill Saffo, Mayor of Wilmington, North Carolina; the Attorney General filed the direct testimony and exhibits of Richard A. Polich and Dan J. Wittliff, Managing Directors, GDS Associates, Inc.; and Commercial Group filed the direct testimony and exhibits of Steve W. Chriss, Director, Energy and Strategy Analysis, Wal-

Mart Stores, Inc., and Wayne Rosa, Energy and Maintenance Manager, Food Lion, LLC. On October 20, 2017, the Commission issued an Order granting the motion of NC Justice Center to extend to October 23, 2017, the deadline to file the direct testimony of witness, John Howat. On October 23, 2017, NC Justice Center filed the direct testimony and exhibits of John Howat, Senior Policy Analyst, National Consumer Law Center.

On October 24, 2017, DEP noticed the depositions of AGO witness Dan J. Wittliff and Public Staff witness Jay B. Lucas.

On October 25, 2017, the Public Staff filed Appendix A to the direct testimony and exhibits of Roxie McCullar.

On October 27, 2017, DEP filed a Motion to Strike Direct Testimony of Michael Murray, President of Mission:data Coalition, filed on behalf of NCSEA. NCSEA filed a response in opposition to DEP's Motion to Strike on October 30, 2017. On November 3, 2017, the Commission issued an Order Granting in Part and Denying in Part DEP's Motion to Strike parts of witness Murray's direct testimony.

On November 6, 2017, DEP filed the rebuttal testimony and exhibits of Company witnesses Fountain; Bateman; De May; Doss; Fallon; Gillespie; Hager; Hevert; Hunsicker; Kerin; McGee; Miller; Simpson; Wright; Donald L. Schneider, Jr., General Manager of Advanced Metering Infrastructure Program Management, DEBS; Michael Delowery, Vice President of Project Management and Construction, DEBS; Thomas Silinski, Vice President of Total Rewards and Human Resource Operations, DEBS; and James Wells, Vice President of Environmental Health and Safety - Coal Combustion Products, DEBS. On the same day, DEP filed the rebuttal testimony and exhibits of external expert witnesses John J. Spanos, Senior Vice President, Gannet Fleming Valuation and Rate Consultants, LLC; and Jeffrey T. Kopp, Manager of Business Consulting Department – Business and Technology Services Division, Burns and McDonnell Engineering Company, Inc. On November 8, 2017, DEP filed the supplemental rebuttal testimony of Company witness Hunsicker.

On November 15, 2017, the Public Staff filed the supplemental testimony of Jay B. Lucas. Also on November 15, 2017, NCLM filed a Motion to excuse its witness, Mayor Bill Saffo, and to accept his pre-filed testimony.

On November 16, 2017, the Commission issued its Order on Hearing Procedure and Availability of Witnesses.

On November 17, 2017, the Commission issued an Order granting the motion of DEP and the Public Staff' to reschedule the expert witness hearing that was scheduled to begin Monday, November 20, 2017, to Monday, November 27, 2017, at 1:30 p.m.

On the same date, the Commission issued an Order granting NCLM's motion to excuse witness Saffo from attending the expert witness hearing.

On November 17, 2017, DEP filed the second supplemental rebuttal testimony and exhibits of Company witness Bateman.

On November 20, 2017, DEP and the Public Staff filed a Preliminary Notice of Partial Settlement, notifying the Commission that they had reached a preliminary partial settlement in principle as to certain issues in this docket.

Also on November 20, 2017, the Public Staff filed the supplemental testimony and exhibits of witnesses Garrett and Moore.

On November 21, 2017, the Commission issued an Order directing that the Intervenors would be permitted to supplement their pre-filed direct testimony with testimony in response to the proposed settlement of DEP and the Public Staff, that the intervenors' witnesses would be subject to cross-examination on their settlement testimony, and that DEP would be allowed to offer rebuttal testimony in response to the intervenors' settlement testimony.

On November 22, 2017, DEP and the Public Staff filed an Agreement and Stipulation of Partial Settlement (Stipulation) that resolved all issues between DEP and the Public Staff, with the exception of: (1) cost recovery of DEP's CCR costs, recovery amortization period and return during the amortization period, allocation issues associated with CCR costs, ongoing costs to be included in rates, and whether certain CCR costs are recoverable under G.S. 62-133.2; (2) the amount of DEP's requested deferred storm costs to be recovered, and the amortization period of any such recovery; and (3) with respect to DEP's proposed Job Retention Rider (JRR), whether companies involved in the transportation or preservation of raw material or a finished product should qualify, and how, or if, the JRR should be funded after the expiration of the initial year's $3.5 million shareholder contribution.

In support of the Stipulation, on November 22, 2017, the Public Staff filed the settlement testimony and exhibits of witnesses Peedin, McLawhorn, Maness, and Parcell. DEP filed the settlement testimony and exhibits of Company witnesses Fountain, Bateman, Hevert, De May, and Wheeler on November 27, 2017.

On November 27, 2017, DEP and Commercial Group filed a Settlement Agreement resolving all issues between them in this docket. On the same date, DEP and Kroger filed a Settlement Agreement resolving all issues between them in this docket.

On November 28, 2017, the Public Staff filed Revised Settlement Exhibit 1 and Peedin Revised Exhibit 1.

On December 4, 2017, the Public Staff filed the corrected supplemental testimony and exhibits of witnesses Garrett and Moore. On the same date, the Public Staff filed Second Revised Peedin Exhibit 1, Schedules 1, 1-1, 3-1, and 3-1(n), and Second Revised Settlement Exhibit 1.

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

Rockingham: Tom Clark, Lois Jones, Keely Wood, Debbie Hall, Tavares Bostic, Kent McGill, Margaret Wolfe-Roberts, Karen Tucker, Kim McCall, Emily Zucchino, Cary Rodgers, John Merrell.

Raleigh: Robert Finch, Sr., Karen Mallam, Tom Clark, Dewey Botts, Harvey Richmond, Patricia M. Walker, Linda Lyons Bakalyan, Robert Gilbert, Ann Busche on behalf of Rama H. Darbha, Martha Girolami, Amanda Robertson, Margaret Toman, Robert Rodriguez, Karen Bearden, Mac Legerton, Dave Carlson, Helen Tart, John Wagner, Irene Cygan, Meredith Bain, Sharon C. Goodson, Jim Seabolt, Lisabeth Svendsgaard, Lynn Marie Sullivan, Laura Michelle Gaines, Elizabeth Adams, Sharon Paterson, Morgan Malone, Fran Lynch, Sharon Jones, Margaux Escutin, Walter Von Schonfeld, Bill Garrity, Deborah Graham, Mark Daughtridge, Rachel Karasik, Kelly Garvy, Jocelyn Tsai, Beth Henry, Suzanne MacDonough, Allison Keenan.

Asheville: Bill Whalen, Dave Hollister, Dan Gilbert, Cathi Culver, Judy Mattox, Kelly Williams, Stephanie Biziewski, Brad Rouse, Xavier Boatright on behalf of Jeri Cruz-Segarra, Ken Brame, Hartwell Carson, Kendall Hall, Marston Blow, Samantha Wilds, Cathy Scott, Judith Kaufman, Steve Carter, Cathy Holt, Jim McGlinn, James Smith, Michael Kohnle, Jamie Friedrick, Lissa Pedersen, Michael Whitmire, Matthew Livsey, Michael Huttman on behalf of Dee Williams, Benjamin Brill, Beth Jezek, Viola Williams, Cari Watson, Sam Mac Arthur, Anne Craig, Carolyn Anderson, Richard Fireman, Sandra Rountree, Carol Stangler, Jeffrey Secrest, Gabrielle White, Elizabeth Laubach, Steven Norris, Audrey Yatras, Xavier Boatright, Patrick Taylor, Katherine Houghton.

Snow Hill: Kristiann Herring, Michael Thomas Carroway, Hope Taylor, Michael Schachter, John Hinnant, Linda Wilkins-Daniels, Bobby Jones, Barbara Dantonio, Johnnie Gurley, Joe Poland, Marvin Winstead, Jr., Edgar R. Bain, Mindy Hodgin, Joan Gallimore, Charles Wright, Willie Battle, Michael Emerson, Dennis Liles, Bill Garrity, Mary Maness, Edith Fail, Nicholas Wood, Wesley Garner, Jr., Sara Mullens, Anne Harrington, Keith Copeland.

Wilmington: Susan A. Bondurant, Peter Gillman-Bryan, Mal Maynard, Alina Szmant, Deborah Dicks Maxwell, Samantha Worrell, Rebecca Louise Stutts, Donald Thackston, Feris Herbert Harkin, Wanda Wooten, Suzanne LaFollette-Black, Daniel Nofziger, Patricia Leonard, Kevin Blackburn, Caylan McKay, Linda Susan Porter, Connette Bradley, Roberta Buckles, Elizabeth Murray, Esther Murphy, Isabelle Sheppard, Bill Garrity, Paul Greiner, Pauline Richardson.

This matter came on for the expert witness hearing on November 27, 2017. DEP presented the testimony of Company witnesses Fountain, Bateman, Hevert, De May, Simpson, Hunsicker, Miller, McGee, Doss, Wheeler, Hager, Fallon, Spanos, Kopp, Schneider, Wright, Wells, and Kerin. The Public Staff presented the testimony of witnesses McLawhorn, Peedin, Moore, Garrett, Maness, Lucas, and Floyd. The Attorney General presented the testimony of witnesses Polich and Wittliff. Sierra Club presented the testimony of witness Quarles. NC Justice Center presented the testimony of witnesses Deberry, Howat, and Wallach. NCSEA presented the testimony of witnesses Murray and Barnes. CUCA presented the testimony of witness O'Donnell. Parties waived cross-examination of Company witnesses Gillespie, DeLowery, and Silinski; Kroger witness Beiber; EDF witness Alvarez; DoD/FEA witnesses Cannady and Mancinelli; Public Staff witnesses Metz, Williamson, Saillor, Parcell, and McCullar; Fayetteville PWC witness Hughes; CIGFUR witness Phillips; NCSEA witness Golin; Sierra Club witness Hausman; NCLM witness Saffo; Commercial Group witnesses Chriss and Rosa; and NC Justice Center witness Howat. The pre-filed testimony of each of these witnesses was copied into the record as if given orally from the stand and their exhibits entered into evidence.

On December 6, 2017, the Public Staff filed Late-Filed Exhibit 1 of witness Floyd in response to the Commission's request during the expert witness hearing. On the same date, DEP filed Late-Filed Exhibits 1 - 5 in response to Commission questions or requests made during the expert witness hearing.

On December 21, 2017, NC Justice Center witness John Howat filed Late-Filed Exhibit JH-9 in response to a request by Chairman Finley during the expert witness hearing.

On December 22, 2017, the Public Staff filed a Motion to Add Maness Late-Filed Exhibit: Difference Between Public Staff and DEP on Coal Ash – After Other Issues (Maness Late-Filed Exhibit) to the Record regarding updates to testimony dealing with DEP's request to recover its costs for coal ash remediation and resulting changes to the Public Staff's and DEP's positions on coal ash costs as a result of the Stipulation. The Commission issued an Order Accepting Maness Late-Filed Exhibit on January 2, 2018. On the same day, the Commission issued an Order to Strike certain portions of NCSEA witness Murray's summary of his pre-filed direct testimony.

On January 4, 2018, DEP filed Late-Filed Exhibit 6 in response to the Commission's questions during the expert witness hearing.

On January 11, 2018, the AGO filed a Late-Filed Exhibit in response to the Commission's request during the expert witness hearing.

On January 12, 2018, proposed orders were filed by DEP and the Public Staff. Partial proposed orders were filed by NCSEA and NCLM. Post-hearing briefs were filed by DEP, AGO, NCSEA, DoD/FEA, Sierra Club, CIGFUR, CUCA, EDF, Fayetteville PWC, NC Justice Center, Commercial Group, Kroger, NCLM, Quad Towns, and NC WARN.

On January 22, 2018, DEP and the NC Justice Center filed a Partial Settlement Agreement.

On January 23, 2018, DEP filed a supplement to its Late-Filed Exhibit 6.

On January 26, 2018, the Commission issued an Order Requesting Additional Information.

On January 29, 2018, DEP filed its Late-Filed Exhibit 7 in response to the Commission's Order Requesting Additional Information.

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

FINDINGS OF FACT

Jurisdiction

1. DEP is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of the Commission. The Company is engaged in the business of generating, transmitting, distributing, and selling electric power to the public in a broad area in eastern North Carolina and an area in western North Carolina in and around the City of Asheville. DEP is a wholly-owned subsidiary of Duke Energy Corporation, and its office and principal place of business are located in Raleigh, North Carolina.

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

3. DEP is lawfully before the Commission based upon its Application for a general increase in its retail rates pursuant to G.S. 62-133 and 62-134 and Commission Rule R1-17.

4. The appropriate test period for use in this proceeding is the 12 months ended December 31, 2016, adjusted for certain known changes in revenue, expenses, and rate base through October 31, 2017.

The Application

5. By its Application and initial direct testimony and exhibits, DEP originally sought a net increase of approximately $477.5 million, or 14.9%, in its annual electric sales revenues from its North Carolina retail electric operations, including a rate of return on common equity of 10.75%. On September 15, 2017, DEP filed supplemental testimony and exhibits that detailed a $57.958 million reduction in its original request, thereby reducing the total Company proposed increase to approximately $419.5 million. On November 17, 2017, DEP filed further supplemental testimony and exhibits detailing additional adjustments to its Application that changed its proposed annual revenue increase to $425.6 million.

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

The Stipulation

7. On November 20, 2017, DEP and the Public Staff (Stipulating Parties) jointly filed a Preliminary Notice of Partial Settlement. On November 22, 2017, the Stipulating Parties filed the Stipulation. On November 27, 2017, DEP entered into settlement agreements with Kroger and Commercial Group that are consistent with the language of the Stipulation. On January 22, 2018, DEP and NC Justice Center entered into a Partial Settlement Agreement. As used herein, "Stipulation" includes the agreements entered into by and between DEP and the Public Staff, DEP and Kroger, DEP and Commercial Group, and DEP and NC Justice Center.

8. The Stipulation is the product of the "give-and-take" in settlement negotiations between the Stipulating Parties, as well as between DEP and Kroger, DEP and Commercial Group, and DEP and NC Justice Center. Further, the Stipulation is material evidence, and is entitled to be given appropriate weight by the Commission, along with all competent and material evidence in the record.

9. The Stipulation resolves only some of the disputed issues between the Stipulating Parties. The Stipulating Parties did not reach an agreement regarding cost recovery of the Company's CCR costs, the recovery amortization period and return during the amortization period, allocation issues associated with CCR costs, the amount of ongoing CCR costs to be included in rates, or whether certain CCR costs are recoverable under G.S. 62-133.2. They also did not agree on the amount of the Company's requested deferred storm costs to be recovered, the amortization period of any such recovery, or the amount of the adjustment to normalize storm expenses on an ongoing basis. Although the Stipulating Parties agreed that the Company's proposed JRR generally complies with the Commission's guidelines adopted in Docket No. E-100, Sub 73, they disagreed on (a) whether companies involved in the transportation or preservation of a raw material or a finished product (e.g., pipeline customers) should qualify; and (b) how, or if, the JRR should be funded after the expiration of the initial year's $3.5 million shareholder

contribution. These issues were left for resolution by the Commission and are addressed later in this Order.

Adjustments to Cost of Service

10. The Stipulation provides for certain accounting adjustments which are set out in detail in Exhibit 1 to the Stipulation. The Stipulating Parties agreed that settlement on those issues will not be used as a rationale for future arguments on contested issues brought before the Commission. For the present case the accounting adjustments outlined in Exhibit 1 to the Stipulation are just and reasonable to all parties in light of all the evidence presented.

11. The Stipulation provides that the Company will amortize the Harris Nuclear Power Plant Combined Construction and Operating License Application (COLA) costs over an eight-year period. This provision of the Stipulation is just and reasonable to all parties in light of all the evidence presented.

12. The Stipulating Parties have agreed that the Company's depreciation rates will be set based on the rates set forth in the Company's most recent depreciation study, subject to the following inputs: (1) a 10% contingency; (2) a 10-year remaining life for the meters that are being retired pursuant to the Company's Advanced Metering Infrastructure (AMI) program; (3) a 70-year R2 curve for Account 356; (4) a negative 10% net salvage for Account 366; (5) a 17-year life for new AMI meters; and (6) a 20-year amortization period for Accounts 391 and 397. This provision of the Stipulation is just and reasonable to all parties in light of all the evidence presented.

13. As set forth in Section III.T. of the Stipulation, the Company agreed to the Public Staff's adjustment to end-of-life nuclear materials and supplies reserve expense, reduced as described in the rebuttal testimony of Company witness Gillespie. The Company also agreed to take appropriate action to manage materials and supplies (nuclear and non-nuclear) to the current practices and procedures utilized by DEC. This provision of the Stipulation is just and reasonable to all parties considering all the evidence presented.

14. The Company's request to establish a regulatory asset at the time of the Asheville plant's retirement for the remaining net book value, and to defer to this regulatory asset any costs related to obsolete inventory, net of salvage, at the time of retirement is just and reasonable to all parties in light of the evidence presented.

15. The Stipulation provides that the appropriate level of excess deferred income taxes (EDIT) to be refunded to customers is $42.577 million annually for the four years following the effective date of the rates approved herein.

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

16. The Stipulating Parties agree that the revenue increase approved in this Order is intended to provide DEP, through sound management, the opportunity to earn an overall rate of return of 7.09%. This overall rate of return is derived from applying an embedded cost of debt of 4.05% 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 DEP's overall rate of return, cost of debt, rate of return on equity, and capital structure.

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

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

19. A 4.05% cost of debt for DEP is reasonable for the purposes of this case.

20. The rate increase approved in this case, which includes the approved rate of return on equity and capital structure, will be difficult for some of DEP's customers to pay, in particular the Company's low-income customers.

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

22. The rate of return on equity and capital structure approved by the Commission appropriately balances the benefits received by DEP's customers from DEP'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 DEP's customers will experience in paying the Company's increased rates.

23. 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 DEP's need to obtain equity financing and maintain a strong credit rating with its customers' need to pay the lowest possible rates.

24. The authorized levels of overall rate of return and rate of return on equity set forth above are supported by competent, material, and substantial record evidence, are consistent with the requirements of G.S. 62-133, and are fair to DEP's customers generally and in light of the impact of changing economic conditions.

Base Fuel Factor and Coal Inventory

25. The North Carolina retail base fuel expense for this proceeding is $807,561,119, and the following base fuel and fuel-related cost factors are just and reasonable to all parties in light of all the evidence presented for purposes of this proceeding (amounts are cents per kilowatt-hour (kWh), excluding regulatory fee): 1.993 for residential customers; 2.088 for SGS customers; 2.431 for MGS customers; 2.253 for LGS customers; and 0.596 for Lighting customers. Billed fuel rates shall be adjusted to reflect changes to DEP's fuel rates approved by the Commission in Docket No. E-2, Sub 1146 that were effective on December 1, 2017.

26. As set forth in Paragraph III.R. of the Stipulation, DEP 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 $76.11 per ton). This rider shall terminate the earlier of: (a) January 30, 2020, or (b) the last day of the month in which the Company's actual coal inventory levels return to a 35-day supply on a sustained basis, as defined in the Stipulation. The reduction to coal inventory included in working capital and the establishment of the increment rider, as set forth in the Stipulation, is just and reasonable to all parties in light of all the evidence presented.

Quality of Service, Vegetation Management, and Service Regulations

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

28. The proposed amendments to DEP's vegetation management plan and Service Regulations are reasonable and serve the public interest, and should be approved.

Power/Forward Workshop

29. Paragraph IV.A. of the Stipulation provides for a technical workshop hosted by DEP during the second quarter of 2018 regarding the Company's NC Power/Forward grid investments. This provision of the Stipulation is just and reasonable.

Lead-Lag Study

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

Cost of Service Allocation Methodology

31. The Stipulation provides for use of the Summer Coincident Peak (SCP) methodology for cost allocation between jurisdictions and among customer classes in this case. For purposes of this proceeding, the Company may continue to use the SCP methodology for allocation between jurisdictions and among customer classes under the provisions of the Stipulation. The provisions of the Stipulation regarding cost of service allocation methodology are just and reasonable to all parties in light of all the evidence presented.

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

Rate Design

33. For purposes of apportioning and assigning the approved increase in base non-fuel and base fuel revenues between the North Carolina customer classes in this proceeding, the apportionment and rate design principles presented by DEP witness Wheeler in his direct testimony, subject to the modification set out in Paragraph IV.F. of the Stipulation, are just, reasonable, appropriate, and nondiscriminatory.

34. The Company shall implement the rate design proposed by witness Wheeler, as well as the specific modifications set out in Paragraph IV.F. of the Stipulation.

Acceptance of Stipulation

35. The Stipulation will provide DEP 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.

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

Storm Costs

37. In Docket No. E-2, Sub 1131 (Sub 1131), DEP filed a petition to establish a regulatory asset and defer until its next general rate case its 2016 incremental storm expenses, which included costs for Winter Storm Jonas, February 2016 Ice Event, Winter Storm Petros, June and July 2016 thunderstorms, Tropical Storm Hermine, and Hurricane Matthew. The Company sought to defer only those storm costs in excess of the $12.7 million approved in the Company's last general rate proceeding. The Company requested total O&M expenses of $80.152 million.

38. In this proceeding, DEP included a pro forma adjustment to the test year to normalize for storm costs to an average level of costs the Company has experienced over

the last ten years. This pro forma adjustment also removed any storm costs from the 10-year average calculation that were included in the Company's 2016 deferral request, and instead included an amortization of the deferred costs over a 3-year period.

39. The Company should not recover the costs of the June and July 2016 thunderstorms as a part of its 2016 incremental storm expenses deferral. The June and July 2016 thunderstorms amounted to $1.720 million in O&M expenses.

40. The normal range of variation of storm costs experienced by the Company in recent years encompasses $27.4 million, and this amount should be deducted from the 2016 incremental storm costs requested by the Company.

41. It is appropriate for the Company to defer and amortize $51.032 million ($80.152 million total requested O&M expense minus $1.720 million for the June and July thunderstorms minus $27.4 million normal storm expense) of its North Carolina retail storm costs incurred in the test year. The $51.032 million deferral should be amortized over a period of five years, beginning in October 2016.

42. It is not appropriate for the Company to defer and amortize the depreciation expense, return on capital expenditures, and carrying costs on deferred costs that it has incurred as a result of storm damage in 2016.

43. The appropriate North Carolina retail normalized annual level of storm costs to be included in the Company's rates in this case is $11.018 million.

Job Retention Rider

44. 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.

45. 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.

46. The Job Retention Tariff (JRT) Guidelines state that this tariff is intended to be temporary and 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 a preferable time frame for the current JRR.

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

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

49. The Company's recovery of the JRR revenue credits should be reduced by $3.5 million each year the JRR is in effect, if more than one year, to recognize the benefit to shareholders of the JRR.

Coal Combustion Residual Cost Deferral

50. 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 coal combustion residuals (CCRs). By Order dated July 10, 2017, the Commission consolidated the DEP request with the present general rate case. DEP and the Public Staff supported the deferral in their testimony in this docket. The deferral request is reasonable and appropriate.

51. DEP 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 overall cost of capital approved in this Order during the deferral period. Ratemaking treatment of such costs will be addressed in future rate cases.

52. 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 through January 2018.

Recovery of CCR Costs

53. Since its last rate case, DEP has become subject to new legal requirements relating to its management of coal ash. These new legal requirements mandate the closure of the 19 coal ash basins at the Company's coal-fired power plants. Since its last rate case, DEP has incurred significant costs to comply with these new legal requirements.

54. On a North Carolina retail jurisdiction basis, the actual coal ash basin closure costs DEP has incurred (netted against the amount already included in the Company's rates following its last rate case) during the period from January 1, 2015, through August 31, 2017, amount to $241,890,000. DEP is entitled to recover these coal ash basin closure costs, less a disallowance of $9.5 million, for a total amount of $232,390,000.[5] The actual coal ash basin closure costs incurred by DEP, less the $9.5 million, are known and measurable, reasonable and prudent, and used and useful in the provision of service to the Company's customers. DEP is entitled to recover these costs through rates. Further, DEP 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

[5] This amount is used in this Order as a placeholder and is subject to a final adjustment using the energy allocation factor adopted by the Commission and to be provided by DEP and the Public Staff.

and reasonable, and absent any management penalty should be approved, and under normal circumstances the Company is entitled to earn a return on the unamortized balance.

55. Under the present facts, a mismanagement penalty in the approximate sum of $30 million is appropriate with respect to DEP'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 $30 million penalty by amortizing the $232,390,000 over five years with a return on the unamortized balance and then reducing the resulting annual revenue requirement by $6 million for each of the five years.

56. DEP further proposes that it recover on an ongoing basis $129,115,000 in annual coal ash basin closure costs, subject to true-up in future rate cases. The amount sought by the Company is based upon its actual test year (2016) spend. The Company's proposal to recover these ongoing costs as a portion of the rates approved in this Order is not approved. Rather, DEP is authorized to record its September 1, 2017, and future CCR costs in a deferral account until its next general rate case.

Requested CCR Fuel Costs

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

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

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

Provisional CCR Cost Recovery

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

CCR Allocation Guidelines

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

62. 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

63. It is appropriate to require that DEP, within 10 days of the resolution by settlement, dismissal, judgment or otherwise of the litigation entitled Duke Energy Carolinas, LLC, et al. v. AG Insurance SA/NV, et al., Case No. 17 CVS 5594, Superior Court (Business Court), Mecklenburg County, North Carolina (Insurance Case), file a report with the Commission explaining the result and stating the amount of insurance proceeds to be received or recovered by DEP. This reporting requirement shall apply even if the case is appealed to a higher court.

64. It is appropriate to require DEP to place all insurance proceeds received or recovered by DEP in the Insurance Case in a regulatory liability account and to hold such proceeds until the Commission enters an order directing DEP regarding the appropriate disbursement of the proceeds. The regulatory liability account should accrue a carrying charge at the overall rate of return authorized for DEP in this Order.

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

Advanced Metering Infrastructure

66. DEP's request to defer to a regulatory asset account the cost of existing AMR meters replaced by AMI meters should be approved.

Accounting for Deferred Costs

67. The Company is authorized to receive a specific amount of revenue for each of the several deferred costs approved by this Order. If DEP receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company should continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case.

Federal Income Tax Changes

68. The effects of the Federal Tax Cuts and Jobs Act of 2017 should be addressed in the separate proceeding that the Commission has initiated for that purpose, Docket No. M-100, Sub 148.

Revenue Requirement

69. After giving effect to the approved Stipulation and the Commission's decision on contested issues, the annual revenue requirement for DEP 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.

70. DEP should recalculate and file the annual revenue requirement with the Commission within 10 days of the issuance of this Order, consistent with the findings and conclusions of this Order. The Company should work with the Public Staff to verify the accuracy of the filing. DEP 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.

71. The appropriate revenue requirement for the first four years should be reduced by the EDIT Rider decrement of $42.577 million.

Just and Reasonable Rates

72. The base non-fuel and base fuel revenues approved herein are just and reasonable to the customers of DEP, to DEP, and to 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 DEP'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, DEP's verified Application and Form E-1, the testimony of DEP witness Fountain, and the entire record in this proceeding.

On June 1, 2017, DEP filed its Application and initial direct testimony and exhibits, seeking a net increase of approximately $477.5 million, or 14.9%, in its annual electric sales revenues from its North Carolina retail electric operations. In its rebuttal testimony filed on November 6, 2017, DEP reduced its requested increase to $419.5 million. In its Second Supplemental Testimony filed on November 17, 2017, the Company modified its requested increase to $425.6 million (a base rate increase of $461.1 million reduced by a five-year annual Excess Deferred Income Taxes Rider of $(35.5 million)). The Company's requested increase was reduced in the Stipulation filed on November 22, 2017, to a requested increase of $306.0 million (a base rate increase of $348.5 million reduced by a four-year annual Excess Deferred Income Taxes Rider of $(42.5 million)). DEP submitted evidence in this case with respect to revenue, expenses, and rate base, using a test period consisting of the 12 months ended June 30, 2016, updated for certain known and actual changes.

Company witness Fountain testified that major generating plant additions and plant-related expenses account for the majority of the total additional requested annual revenue requirement. (Tr. Vol. 6, p. 33.) The remainder of the requested rate adjustment is to recover costs related to environmental requirements associated with the mandated closure of ash basins, expenses to respond to significant storms, costs for renewable purchased power investment, deferred nuclear development costs, and investments necessary for computer information systems and other ongoing operational costs. (Id.)

Witness Fountain detailed the Company's recent investments to build and purchase additional generating facilities, as well as its updates to improve existing facilities. (Id. at 33-34, 37-39.) He described numerous nuclear, fossil, hydro, and solar projects that DEP has completed since its last rate case. (Id.) For example, the Company has invested heavily in new gas-fueled generation, replacing half of its older, less-efficient coal-fired generation units with state-of-the-art, cleaner burning natural gas-fueled plants. (Id. at 34.) According to witness Fountain, these new plants emit carbon dioxide at about half the rate, and nitrogen and sulfur oxide emissions at a fraction of the rate of the units they replaced. (Id.) In addition to the $416 million invested in gas-fueled plants discussed above, the Company has also invested $184 million in new solar energy installations, the first solar additions to the DEP fleet. (Id.) These additions to the DEP fleet have occurred during a time when the Company has also been making other significant necessary investments in its existing generating plants, such as new pollution controls like the Zero Liquid Discharge flue desulfurization systems for existing coal plants, including a $141 million system at the Mayo Unit 1 facility that provides operational flexibility and reduces environmental impact. (Id.)

Witness Fountain also provided an overview of the CCR basin closure costs the Company is seeking to recover in this case, as well as the Company's proposed recovery of severe storm costs. (Id. at 39-44.) The Company's base rate request also includes development costs for the nuclear development work completed for the Harris nuclear site. (Id. at 40.) Additionally, DEP is seeking to include costs to implement a new Customer Information System (CIS). (Id. at 40, 44-45.) These annual costs are partially offset by the return of a deferred tax liability to customers. (Id.)

Witness Fountain explained that under DEP's proposed rate adjustment customers would 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 46.) He pointed out that customers' bills have also declined from those approved in 2013 due, in part, to the Company prudently managing fuel costs and jointly dispatching the generation fleet to save $183 million. (Id. at 45.)

Witness Fountain also described the Company's ongoing efforts to mitigate customers' rate impacts. (Id. at 48-54.) He stated that to help customers reduce bills, the Company is continuing to expand and enhance its portfolio of demand-side management (DSM) and energy efficiency (EE) programs. (Id. at 49.) According to witness Fountain, the Company offers customers more than a dozen energy-saving programs for every type of energy user and budget, and EE programs currently save its customers in the Carolinas over 1.7 billion kWh annually, or over $170 million, which is about four percent of total retail sales. (Id. at 50.) Combined, its DSM and EE programs offset capacity requirements by the equivalent of over four power plants. (Id.) Witness Fountain also described how the Company's Energy Neighbor Fund helps low-income individuals and families cover home energy bills. (Id. at 51.) Over the life of the program it has provided approximately $32 million to customers. (Id.) He explained that the Company also allows customers to spread out the impacts of seasonal fluctuations into 12 equal monthly payments. Payments can also be made in many different ways to minimize missed payments. (Id. at 51-52.)

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 DEP's 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. 7-9

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the testimony of DEP witnesses Fountain, Bateman, Hevert, De May, and Wheeler, and the testimony of Public Staff witnesses McLawhorn, Peedin, Maness, and Parcell.

The Public Staff and DEC filed a Preliminary Notice of Partial Settlement on November 20, 2017, and on November 22, 2017, they filed the Stipulation. The Stipulation was based on the same test period used by the Company in its Application, with updates.

Witness Fountain explained that the Stipulation resolves all revenue requirement issues between the Company and the Public Staff, except issues related to CCR cost recovery and issues related to recovery of the costs the Company incurred in restoring service and rebuilding the grid following numerous storms in 2016, including winter storm Jonas and Hurricane Matthew. (Tr. Vol. 6, pp. 88, 94-95.) In addition, although the Stipulating Parties reached agreement on most of the issues involving the Company's proposed JRR, there are remaining issues regarding the JRR that the Public Staff and DEP were unable to resolve. (Id. at 95.)

Witness Fountain outlined the key aspects of the Stipulation as follows:

1. Capital Cost and Structure - The Stipulating Parties have agreed to a rate of return on equity of 9.90%, based upon a capital structure containing 52% equity and 48% debt, as described by witnesses Hevert and De May, and a cost of debt of 4.05%. The resulting weighted average rate of return is 7.09%.

2. Updated Plant and Accumulated Depreciation – Plant and accumulated depreciation shall be calculated through October 31, 2017.

3. Updated revenues – Revenues shall be annualized through October 31, 2017.

4. Asheville CWIP - The Company shall update its post-test year additions to include Asheville construction work in progress through October 31, 2017.

5. Inflation – The effects of inflation shall be updated, except the effects of inflation on vegetation management shall be removed.

6. Update labor – The Company's annualized labor costs through September 30, 2017 shall be included.

7. Depreciation Rates – The Company's depreciation rates shall be set based on the rates set forth in the Company's filed Depreciation Study, with exceptions described in the Stipulation.

8. Distribution Vegetation Management – The Public Staff and the Company have agreed to the Company's filed position on distribution vegetation management costs.

9. Harris Combined Construction and Operating License Application (COLA) cost amortization – The Company agrees with the Public Staff's recommendation to amortize such costs over an eight-year period.

10. Customer Connect Expenses – The Company accepts the Public Staff's adjustment, but shall be authorized to establish a regulatory asset to defer and amortize expenses associated with its Customer Connect project. 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 Allowance for Funds Used During Construction (AFUDC). AFUDC shall end and a 15-year amortization shall begin on the date the DEP Core Meter-to-Cash release (Releases 5-8) of the project goes into service or January 1, 2022, whichever is sooner.

11. Revenue Requirement Reductions – The Stipulating Parties agreed to revenue requirement reductions for Aviation, Lost Industrial Revenues Due to Hurricane Matthew, Executive Compensation, Board of Directors, Lobbying, Sponsorships and Donations for the U.S. Chamber of Commerce, Incentive Compensation, and Outside Services.

12. Coal Inventory – The Stipulating Parties agree that for purposes of settlement, the Company may set carrying costs included in base rates assuming a 35-day coal inventory at 100% capacity factor (full load burn),

and that a Coal Inventory rider should be allowed to manage the transition, and that the rider will terminate upon the sooner of the Company reaching a 35-day coal inventory on a sustained basis or two years from approval by the Commission. The Company will conduct an analysis in consultation with the Public Staff demonstrating the appropriate coal inventory level given market and generation changes since the Company's last rate case. The analysis shall be completed by December 31, 2018.

13. Mayo Zero Liquid Discharge and Sutton combustion turbine projects – The Company will make an adjustment to rate base with depreciation expense and other cost of capital effects to reflect the resolution reached in the Stipulation. The adjustment will be permanent for ratemaking and regulatory accounting purposes, and will result in a decrease to the revenue requirement from the Company's filed request. The Company agrees to these adjustments in an effort to reach a settlement on all non-CCR and storm related issues and does not admit and explicitly rejects any imprudence on behalf of the Company regarding the management of the two projects.

14. Nuclear Materials and Supplies - The Company accepts the Public Staff's adjustment to end-of-life nuclear materials and supplies reserve expense, as refined in the testimony of Company witness Gillespie, and agrees that it will take appropriate action to conform its practices and procedures to manage its Materials and Supplies inventory (nuclear and non-nuclear) to the current practices and procedures utilized by Duke Energy Carolinas, LLC, with the goal to ensure that proper levels of inventory are on hand. DEP shall complete this action within 24 months after the entry of the Commission rate case order.

15. Duke-Piedmont Merger Costs - The Company accepts the Public Staff's recommended adjustment to remove the Duke-Piedmont merger costs to achieve.

16. Power/Forward Carolinas Initiative – To address concerns raised in this docket by multiple parties, the Company will host a technical workshop during the second quarter of 2018 regarding the Company's NC Power/Forward grid investments to explain the need for and ongoing benefits of grid investments, and to hear feedback from stakeholders in attendance. The Company will report the results of the workshop to the Public Staff and the Commission. Participation by or attendance of the Public Staff at the NC Power/Forward workshop shall not estop the Public Staff from investigating or making recommendations regarding any element of the Company's NC Power/Forward program in a future rate case or pursuant to applicable statutes or Commission Rules.

17. 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 Wheeler and Hager and Public Staff witness Floyd.

18. Excess Deferred Tax Liability – The Stipulating Parties have agreed to the return of an excess deferred tax liability to customers over the next four years through a rider.

19. Basic Customer Charge - The Company and Public Staff have agreed upon a Basic Customer Charge for Schedule RES of $14.00 per month, and further agree upon a Basic Customer Charge for Schedules R-TOUD and R-TOU of $16.85 per month.

Id. at 88-92.

Witness Fountain testified that the Stipulation was reached after extensive discovery conducted by the Public Staff and other intervenors. He testified that the Stipulation represents a balanced settlement by the parties, and is in the public interest.

DEP witnesses Bateman, Hevert, De May, and Wheeler 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. Witness Hevert stated that the stipulated rate of return on equity, although lower than he had recommended, was nevertheless reasonable, particularly in light of the Company's low cost of debt. Witness Wheeler testified concerning the effects of the partial settlement on DEP's proposed JRR, and witness Bateman presented exhibits showing the monetary effect of the various issues addressed in the Stipulation.

Public Staff witnesses McLawhorn, Peedin, Maness, and Parcell also supported the Stipulation. Witness McLawhorn stated that the principal benefits of the Stipulation are a significant reduction in the Company's proposed revenue increase in this proceeding and the avoidance of protracted litigation by the Stipulating Parties before the Commission and, possibly, the appellate courts. Witness Peedin presented schedules showing the financial impact of each concession made by the Company or the Public Staff, as well as the amount of the rate increase that would result if the Commission agrees with the Company on all the unresolved items, or, alternatively, agrees with the Public Staff on all of these items. 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.

On January 22, 2018, DEP and NC Justice Center filed a Partial Settlement Agreement. In summary, the Partial Settlement Agreement states that DEP will contribute $2.5 million to the Helping Home Fund for low-income energy assistance, and NC Justice

Center will withdraw its claim that the Commission should order DEP to fund energy assistance for low-income ratepayers.

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

> [A] stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding. The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes "its own independent conclusion" supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.

348 N.C. at 466, 500 S.E.2d at 703.

However, as the Court made clear in CUCA II, the fact that fewer than all of the parties have adopted a settlement does not permit a court to subject the Commission's Order adopting the provisions of a non-unanimous stipulation to a "heightened standard" of review. CUCA II, 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court held that Commission approval of the provisions of a non-unanimous stipulation "requires only that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] satisf[y] the requirements of chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties." Id. at 231-32, 524 S.E.2d at 16. The Commission gives substantial weight to the testimony of the Company and Public Staff witnesses regarding the Stipulation, and finds and concludes that the Stipulation is the product of the "give-and-take" of the settlement negotiations between DEP and the Public Staff, as well as between DEP and Kroger, DEP and Commercial Group, and DEP and NC Justice Center, in an effort to appropriately balance the Company's need for rate relief with the impact of such rate relief on customers.

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

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-15

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

The Stipulation resolved many, but not all, of the issues in dispute between the parties. Among other matters, the parties agreed on many accounting adjustments, including: (1) amortization of the costs of the Harris COLA over an eight-year period; (2) the establishment of a regulatory asset to defer and amortize expenses associated with the Company's Customer Connect project; (3) disallowance of certain costs related to the Mayo Zero Liquid Discharge and Sutton combustion turbine projects; and (4) basing the Company's depreciation rates on the rates set forth in the Company's most recent depreciation study, subject to application of certain inputs. DEP witness Bateman presented exhibits showing the monetary effect of the various issues (accounting adjustments and otherwise) addressed in the Stipulation. Public Staff witness Peedin presented schedules showing the financial impact of each concession made by the Company or the Public Staff, as well as the amount of the rate increase that would result if the Commission agrees with the Company on all the unresolved items, or, alternatively, agrees with the Public Staff on all these items. The accounting adjustments that are not specifically addressed in other findings and conclusions of this Order are discussed in more detail below.

<u>Update plant and accumulated depreciation to October 31, 2017</u>

DEP witness Bateman testified that as part of settlement, the Stipulating Parties agreed to update both plant additions and accumulated depreciation through October 31, 2017. As part of this adjustment, for purposes of settlement, DEP and the Public Staff agreed to remove the Company's adjustments to accumulated depreciation that were contained in its adjustments NC-0800 and NC-1100. The Company also agreed to update its post-test year additions to plant to include Asheville CWIP through October 31, 2017.

<u>Update revenues to October 31, 2017</u>

DEP witness Bateman testified that as part of the settlement, the Stipulating Parties agreed to update revenues to reflect changes in number of customers and, for the residential class, changes in weather-normalized usage per customer through October 31, 2017. The Stipulation also provides that the Company shall annualize revenues and include the effects of inflation through October 31, 2017.

<u>Update labor costs through September 30, 2017</u>

The Stipulation requires the Company to update its labor costs through September 30, 2017.

Adjust for lost industrial revenues due to Hurricane Matthew

As discussed by Company witness Bateman, DEP made an adjustment to increase revenues to reflect the estimated net lost revenues from residential and commercial customers as a result of Hurricane Matthew. Public Staff witnesses Peedin and Williamson testified that because industrial customers were also affected by the hurricane, the Public Staff recommends modifying this adjustment to include the net lost revenues from the industrial class.

In her rebuttal testimony, witness Bateman testified that the Company does not oppose Public Staff' witness Williamson's recommendation to include the impact of lost industrial revenue due to Hurricane Matthew. However, the Company does oppose the calculation proposed by witness Williamson. In its initial adjustment regarding lost revenue due to Hurricane Matthew, the Company stated that it did not include industrial class customers in the estimate because "using customer averages would not be reliable due to significant usage differences among customers" for this class. Witness Williamson used average daily usage for the industrial class in his calculation. Because of the impact that a handful of extremely high usage customers can have on this average calculation, the Company looked at the detailed hourly customer data for industrial customers on the Real Time Pricing rate schedule. Using this approach, the Company was able to determine that 21 of these high usage customers did not lose power as a result of the storm. Therefore, as she explained in her rebuttal testimony, witness Bateman recalculated witness Williamson's adjustment to exclude these customers from the average daily usage calculation. As part of settlement, the parties agreed to accept the Public Staff's adjustment with the modification proposed in witness Bateman's rebuttal testimony.

Adjust aviation expenses

In its initial filing, the Company removed 40.24% of the corporate aviation costs. In its adjustment, the Public Staff removed 75.55% of the costs. For the purposes of settlement, the parties agreed to an adjustment that removes 50% of the costs.

Adjust 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 DEP in the Test Period. Witness Bateman explained that while the Company believes these costs are reasonable, prudent, and appropriate to recover from customers, DEP has, for purposes of this case, made an adjustment to this item.

Public Staff witness Peedin 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.18, pp. 67-70.) Witness Peedin recommended disallowance of incentive compensation related to earnings per share (EPS) and total shareholder return (TSR). (Id.) Witness Peedin asserts that incentive compensation tied to EPS and TRS metrics should be excluded because it provides a direct benefit to shareholders only, rather than to customers. (Id. at 70.) Witness Peedin also asserts that executive compensation and benefits should be excluded because these executives' duties are closely linked to shareholder interests. (Id.) DoD/FEA witness Cannady also recommended removal of non-qualified pension expense. (Tr. Vol. 17, p. 183.) Witness Cannady, while acknowledging that the Commission has historically allowed non-qualified pension expense, advocates its exclusion in this case because of her belief that customers should not be responsible for benefits available only to management and executive employees at the higher end of the pay scale. (Id. at 183-84.)

In his rebuttal testimony, Company witness Silinski testified that these proposed adjustments are inappropriate and should be rejected by the Commission. Witness Silinski explains that witnesses Peedin and Cannady erroneously assume a divergence of interests between shareholders and customers that does not, in fact, exist. (Tr. Vol. 13, p. 56.) To the contrary, employee compensation and incentives tied to metrics such as EPS and TSR directly benefit customers, because those metrics reflect how employees' contributions translate into overall financial performance. (Id.) EPS, for example, is a direct 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 witness Peedin's proposed adjustment to disallow incentive recovery would wipe out recovery of compensation for employees who are directly focused on and responsible for vital customer service functions, such as engineers, distribution instrument and control technicians, transmission substation technicians, distribution line technicians, customer care associates, system operators, and nuclear plant control operators. (Id. at 59-63.) Disallowing a portion of the compensation for these employees sends a signal to the Company that these costs provide no value to the customer and should, therefore, be eliminated. (Id. at 64.) Finally, 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 57.) The recommended adjustments would render the Company's compensation uncompetitive with the market, which would result in the inability to attract and retain the talent the Company needs to run a safe and reliable electric system. (Id.) Witness Silinski pointed out that no witness in this proceeding challenges the reasonableness of the level of compensation expenses reflected in the rate-making test period for the Company. (Id.) Nor has anyone challenged that the compensation and benefit programs are necessary and critical in their entirety for attracting, engaging, retaining, and directing the efforts of employees with the skills and experience necessary to safely, efficiently, and effectively provide electric services to DEP customers. (Id.) Accordingly, for the Commission to abrogate these incentives and benefits would be a severe detriment to customers and would result in disallowance of a prudently incurred cost. (Id.)

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 Paragraph III.F.)

As part of settlement, 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.Q. of the Stipulation, which provides that the Company's employee incentives should be adjusted to remove the cost of the STIP Plan based on the Company's EPS for employees who qualify for the Company's LTIP.

Adjust Sutton CT Blackstart plant cost

In its Application, the Company requested that its capital investment in the Sutton

Blackstart CT combustion turbine project, approximately $120 million, be included in rate base. In his direct testimony, Public Staff witness Metz recommended that approximately $6.4 million of the project be excluded from rate base, which represents the costs associated with sending the combustion turbines (CTs) to a General Electric (GE) service facility in Houston, Texas for disassembly and cleaning after debris was discovered in one of the CTs. (Tr. Vol. 7, p. 315.)

In his rebuttal testimony, Company witness Delowery testified that the Company believes that it appropriately and prudently managed the construction and associated costs of the project and notes that the project was delivered on time and below the estimated budget. (Id. at 363-364.) Witness Delowery further stated that Company believes it was prudent in its actions to return the equipment to GE when it discovered the issues and, therefore, should not be penalized for safety/operational decisions. Additionally, witness Delowery testified that the actual cost of the removal of the equipment, disassembly, inspection, leasing of replacement engines, and reassembly totaled $4.6 million, not $6.4 million. (Id. at 363.)

As part of Stipulation, the parties agreed to reduce rate base by $2.788 million (NC retail), along with other depreciation expense and cost of capital effects. Witness Bateman explained that while DEP believes these costs were prudently incurred, for the purposes of settlement, the Company has agreed to the adjustment. The Stipulation provides that this adjustment shall be permanent for ratemaking and regulatory accounting purposes.

Adjust Mayo Zero Liquid Discharge plant cost

In its Application, the Company requested that its approximately $147 million capital investment in the Mayo Unit 1 Zero Liquid Discharge (ZLD) treatment system for flue gas desulfurization wastewater for environmental compliance and operational flexibility be included in rate base. In his testimony, Public Staff witness Lucas testified that the project experienced construction delays and cost overruns and, therefore, $34.3 million, the difference between the final project costs and DEP's estimate at the outset of the project, should be excluded from rate base. (Tr. Vol. 18, p. 229.)

In his rebuttal testimony, Company witness Delowery testified that the Company appropriately managed the construction of the project, that all costs for the project were prudently incurred, and, therefore, that the Public Staff's recommendation should be rejected by the Commission. (Tr. Vol. 7, p. 348-350.) In support, witness Delowery testified that the Company followed its extensive bidding processes and evaluation criteria to procure the selected contractors and a contracting strategy that appropriately managed risks and costs, based on what the Company knew or should have known at the time, which were prudent actions. (Id. at 348-49.) He further stated that, excluding the power agency share, the final project costs was only 4% higher than the Company's cost estimate range at project approval. (Id. at 355.)

As part of settlement, the parties agreed to reduce rate base by $10.393 million (NC retail), along with depreciation expense and other cost of capital effects. Witness Bateman explained that while DEP believes these costs were prudently incurred, for the purposes of settlement, the Company has agreed to the adjustment. The Stipulation provides that this adjustment shall be permanent for ratemaking and regulatory accounting purposes.

Vegetation Management

In its Application, the Company did not include any adjustment to its test period vegetation management expenses. Company witness Simpson testified that "[v]egetation management is a critical component of the Company's power delivery operations and the continued effort to drive performance for customers' benefit." (Tr. Vol. 9, pp. 29-30.) Witness Simpson explained that in addition to routine circuit maintenance, the Company's vegetation management program includes herbicide spraying, removal of hazard trees outside the area normally maintained on a distribution line, certain unplanned work due to recommendation by reliability engineers or customer requests, and a formal review process following vegetation-related outages. (Id. at 30.)

In response to the Company's request, Public Staff witness Peedin recommended adjusting the Company's target vegetation management cycle from 6 years to 7 years. (Tr. Vol. 18, p. 76.) Based on such an adjustment, witness Peedin recommended reducing the Company's test period vegetation management expenses by $4.06 million. (Id.)

In response, Company witness Simpson testified that witness Peedin's adjustment does not take into account the contract rate increase of 4.18% which the Company expects for future vegetation management contracts, driven by a tightening labor market and increased safety standards. (Tr. Vol. 9, pp. 49-50.) Witness Simpson further testified that the Company is considering a shift to a 7-year cycle for vegetation management, but that plan has not yet been approved. (Id. at 50.)

The Company thereafter modified its request to increase test period vegetation management expense by $1.48 million. (Updated Bateman Exhibit 1 – Hearing, p. 3, line 37.) This adjustment included the impact of the cycle change recommended by witness Peedin and the increase in contract rates supported by witness Simpson.

The Stipulation provides that the Public Staff withdraws its recommended adjustment to the Company's test period vegetation management expenses. The Company also withdraws its recommended adjustment to the test period vegetation management expenses included in the second supplemental testimony of witness Bateman filed November 17, 2017. The effect of this is that the Stipulating Parties agree with the Company's original position filed in this case.

Outside Services

Witness Peedin testified that during 2016, the test year in this case, the Public Staff reviewed costs for outside services associated with expenses that were indirectly charged to DEP by Duke Energy Business Services (DEBS) as well as those incurred by the Company directly. Witness Peedin 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. She recommended removing these expenses from O&M in the test period. Witness Peedin noted that the Public Staff also found certain expenses that were allocated to DEP that should have been directly assigned to other jurisdictions that she recommended be removed. In the Stipulation, the Company agreed that $80,000 of costs associated with outside services should be removed, as recommended by the Public Staff and reflected on Settlement Exhibit 1. This amount does not include costs incurred for certain legal services related to coal ash, which are included in the Unresolved Issues, as described in the Stipulation.

Removal of costs to achieve Duke Energy-Piedmont merger

On September 29, 2016, in Docket Nos. E-7, Sub 1100, E-2, Sub 1095, and G-9, Sub 682, the Commission issued its Order Approving Merger Subject to Regulatory Conditions and Code of Conduct (Merger Order), which approved the merger between Duke Energy and Piedmont Natural Gas Company (Piedmont).

During the test year in this case, DEP has included in operating expenses approximately $3.8 million on a North Carolina retail basis that it identified as systems and transition costs to achieve merger savings. DEP has not requested recovery of these costs in rate base, but instead has chosen to include them in O&M expenses. Witness Peedin explained that the Public Staff believes that the Company is not permitted to recover these costs in this manner by the Merger Order. (Tr. Vol. 18, p. 74.)

In her rebuttal testimony, witness Bateman explained that the Company opposed this adjustment. (Tr. Vol. 6, p. 162.) She noted that the costs that witness Peedin has removed are operating expenses, not capital costs. (Id. at 162-63.) According to witness Bateman, the Merger Order does not specifically address cost recovery for operating expenses associated with achieving merger savings. (Id. at 163.) Witness Bateman explained that operating expenses are different from capital costs, and the Company cannot simply capitalize and depreciate operating expenses like witness Peedin suggests. (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 these issues. Accordingly, the Stipulation provides that the Company accepts the Public Staff's proposed adjustment to remove costs to achieve the Duke Energy/Piedmont merger

Adjust Allocations by DEBS to DEP

DEBS is the company that provides services to various affiliated entities of Duke Energy Corporation. (Tr. Vol. 18, p. 74.) As discussed above, during the test year Duke Energy acquired Piedmont, and the Commission approved the merger on September 29, 2016. (Id.) According to Public Staff witness Peedin, this change, along with updates related to other affiliated entities, has caused the DEP allocation factors to decrease. (Id.) As part of settlement, the parties agreed to accept the Public Staff's adjustment with a modification to include an annualized amount of DEBS costs related to Piedmont in the calculation. (Id.)

Lobbying and Board of Director expenses

Witness Peedin made an adjustment to remove 50% of the expenses associated with the Board of Directors of Duke Energy that have been allocated to DEP. (Tr. Vol. 18, p. 69.) She explained that the rationale for this adjustment is closely linked to the premise of the adjustment made by the Public Staff related to executive compensation. (Id.)

With respect to lobbying expenses, witness Peedin noted that the Company made an adjustment to remove some lobbying expenses from the test year. (Id. at 75.) 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.) In her rebuttal testimony, witness Bateman explained why the Company opposed this adjustment and disagreed with witness Peedin's characterization of these expenses. (Tr. Vol. 6, p. 166.) Witness Bateman testified that in 2016, the Company engaged a third-party consulting company to perform a detailed time study for the purpose of determining the percentage of time certain individuals spent on lobbying activities per the federal definition in Title 29, Section 367.4264 of the Code of Federal Regulations. (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. at 167.) The results are that in the test period, the company booked below the line 66% of the expenses for federal affairs, 75% of the expenses state government affairs, and 10% of the expenses for stakeholder engagement. Witness Bateman concluded that no further adjustments were necessary or justified. (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.W. of the Stipulation, the Company agreed to accept the Public Staff's recommended adjustments to lobbying and Board of Directors' expenses. Both parties presented evidence to support their respective positions in direct and rebuttal testimony; however, no party provided clarity regarding the settled position. As previously discussed, the Stipulation is recognized as a series of give-and-take positions by the party.

Sponsorship Expenses

The Stipulation provides that the Company's sponsorships and donations expense should be reduced by the amount paid to the U.S. Chamber of Commerce.

Harris COLA

In 2006, DEP selected a site at the Shearon Harris Nuclear Power Plant in Wake County, North Carolina to evaluate the possibility of nuclear expansion to serve North Carolina and South Carolina customers. As Company witness Fallon explained, new nuclear generation has a long lead time to license and construct. (Tr. Vol. 12, p. 39.) As such, actions must be taken in advance of construction to ensure a nuclear option is available when needed by customers. From 2005 through early 2013, the Company undertook the activities necessary to develop a COLA for the Harris Nuclear Project (HNP).

In 2013, the Company determined that additional nuclear units were no longer needed within the planning horizon of the IRP. As witness Fallon explained, the Company determined that proceeding with the HNP was no longer necessary and no longer in the best interest of customers. (Id.) As a result, the Company filed, and the Commission approved in Docket No. E-2, Sub 1035, a petition seeking an accounting order to defer and amortize the capital costs incurred relating to the HNP. DEP incurred approximately \$70.3 million in HNP costs. (Tr. Vol. 12, p. 25.) Company witness Fallon explained that the North Carolina allocable share of the development costs is approximately \$45.3 million.

The Company proposed a five-year amortization period in this rate case to recover the cost expended on the HNP. Public Staff witness Peedin recommended modifying the amortization period from five years to eight years. The Stipulating Parties have agreed to the recovery of the HNP costs over an eight-year amortization period as recommended by Public Staff witness Peedin.

DoD/FEA witness Cannady recommended that the Commission disallow all HNP costs that the Company incurred after 2011 as being imprudent. (Tr. Vol. 17, p. 175.) Witness Cannady based her conclusion on: (1) a reduction in spending on internal labor and other direct costs from 2011 to 2013, (2) a statement of then CEO Jim Rogers that the decision to build new nuclear depended on gas prices, carbon assumptions, and growing demand, which she then attempted to demonstrate were not supportive of new nuclear at the time, and (3) the results of a third-party IRP analysis performed for DEP in 2012 that supports a conclusion that DEP should have stopped the project in 2011.

According to witness Cannady, the Company reduced internal labor costs and overall COLA-related activity after 2011. Witness Cannady argued that this evidenced that the Company no longer viewed pursuit of the COLA after 2011 as prudent. (Tr. Vol. 17, p. 178.) Based on the DEP response to DoD/FEA Data Request No. 1, Item 1-16, the internal labor and other direct costs averaged $4 million annually from March 2008 through December 2011, and only $1.1 million from January 2012 through May 2013. (Id.) Witness Cannady contends that if the Company remained convinced that continued pursuit of the COLA after 2011 was prudent, it would have addressed issues surrounding the AP1000, emergency preparedness, outstanding Nuclear Regulatory Commission (NRC) requests for information, and other environmental concerns expressed by the U.S. Army Corps of Engineers. (Id.)

In response, witness Fallon explained in his rebuttal that direct cost and labor cost and/or the varying spending levels are not indicators of how aggressively DEP is pursuing the project. Instead, these costs are driven by a variety of factors, including nuclear review schedule. Witness Fallon highlighted that DEP pursued the COLA in a deliberate and methodical fashion, with appropriate cost levels for labor and direct costs throughout the project. (Tr. Vol. 12, p. 52.) In regard to the NRC schedule, witness Fallon explained that DEP expended significant effort responding to the Requests for Additional Information (RAIs) over the 2008-2011-time period. (Id. at 53.) Over time, as DEP answered the RAIs, the workload and spending decreased. By the end of 2011 and the start of 2012, DEP had very few outstanding RAIs, and the NRC's primary focus was on approving the AP1000 DCD and issuing Combined Licenses (COLs) to the Vogtle and V.C. Summer projects. (Id.) During that same time, other factors, such as the review of the Waste Confidence Rule, also impacted the level of activity. Witness Fallon further pointed out that witness Cannady's analysis distorts the average by comparing full year spend for the period against less than five months of spend in 2013 when the Harris COLA was suspended. (Id. at 54.) He went on further to explain that the data request response relied upon by witness Cannady for her analysis demonstrates that there have been significant swings in labor cost and direct cost throughout the course of the HNP. (Id.) In addition, where labor cost declined from 2011 to 2012, overall spending on the project was almost the same in 2011 and 2012. (Id. at 54-55.)

Witness Cannady also argued that a 2012 statement of Duke Energy CEO Rogers further established the imprudence of moving forward with the Harris COLA. (Id. at 179.) The statement refers to decisions on nuclear being strongly related to a price on carbon and the cost of natural gas. Witness Cannady contends that the Company should have reevaluated nuclear energy based upon changes to natural gas and carbon. (Id. at 179-80.) Witness Cannady argued further that DEP'S IRP showed in 2012 that there would not be enough additional demand to justify a nuclear plant until at least the 2030-35 timeframe. (Id. at 180-81.)

As it relates to the resource planning statement made by Jim Rogers, witness Fallon explained that witness Cannady's near-term focus on current gas assumptions and demand growth failed to understand that DEP appropriately considers these factors through the Company's IRP process, and builds its generation system to meet customer needs in the future and over a long-term planning horizon. (Tr. Vol. 12, p. 58.) Although witness Cannady utilized historical natural gas prices to justify her conclusions, the Company does not make future resource decisions based on near-term historical natural gas prices. (Id. at 58.) The Company appropriately relied upon the IRP. In addition, potential carbon legislation, regulation, and litigation were major concerns for the industry in the 2012-2013 timeframe, with many coal-fired plants being shut down across the country to comply with environmental regulations. The Clean Power Plan was not proposed until June 2014, well after the HNP was suspended. Finally, DEP witness Fallon testified that the Company's decision to hire an independent consultant to perform a long-term needs assessment, which was not completed until February 2013, was a prudent and reasonable decision to ensure that DEP was appropriately planning its system for future customer needs and that suspending the Harris COLA review would not harm customers based on the current projected needs.

Based on the discussion above and the evidence in the record, the Commission disagrees with DoD/FEA's position that the Commission should disallow all costs associated with the Harris COLA that the Company incurred after 2011 as being imprudent. The Commission agrees with Company witness Fallon that the Company appropriately relied on its IRP conclusions to make the determinations of what types of resources were needed and when. The Commission further agrees with DEP witness Fallon that major changes and concerns (specifically environmental regulations) were being contemplated in the utility industry in the 2012-2013 timeframe that would affect future decisions. Further, the Commission finds that DEP was prudent and reasonable with its decision to hire an independent consultant to perform a long-term needs assessment to review the ramifications of the Harris COLA review and future system planning needs. For the reasons discussed above, the Commission finds and concludes that DOD/FEA's recommendation to disallow the Harris COLA costs should be rejected.

With respect to other intervenors, NC WARN contends in its post-hearing Brief that DEP should be limited on recovering costs associated with the HNP. NC WARN states that the Commission should find that none of the costs associated with the predevelopment and COLA preparation for the HNP should be borne by ratepayers. NC WARN notes that recovery of the costs associated with the Harris COLA was included in the Stipulation between the Company and the Public Staff, with amortization of the costs over eight years. NC WARN states in its Brief that the final determination as to what is just and reasonable to be included in rates is up to the Commission, not the settling parties. NC WARN further discusses the setting or "fixing" of rates by the Commission. NC WARN stated that G.S. 62-133(b) states that the Commission must:

> Ascertain the reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service rendered to the public within the State, less that portion of the cost that has been consumed by previous use recovered by depreciation expense. In addition, construction work in progress may be included in the cost of the public utility's property under any of the following circumstances:

> a. To the extent the Commission considers inclusion in the public interest and necessary to the financial stability of the utility in question, reasonable and prudent expenditures for construction work in progress may be included, subject to the provisions of subdivision (4a) of this subsection.

NC WARN recounts the history of DEP's filings with the NRC and the Commission, beginning in 2008 and including DEP's petition filed on August 15, 2013, for an accounting order to defer in a regulatory asset account certain costs incurred with regard to the Harris COLA. NC WARN states that in the period between 2008 and 2013, DEP incurred costs of approximately $69 million on the project, and that the North Carolina jurisdictional allocation of this amount is approximately $45 million. (Tr. Vol. 12, page 48) NC WARN notes that DEP seeks recovery of the entire amount of funds spent on the licensing of the HNP.

Further, NC WARN opines that prior to Senate Bill 3, Session Law 2007-397, it could be argued that development costs for any project should be borne by the utility, and not the ratepayers, unless the plant comes online and is used and useful. Additionally, NC WARN states that in Senate Bill 3 the General Assembly made an exception to the general rule, and specifically for nuclear plants, as the costs of development and construction are disproportionate to those of other generating facilities and the timeline for development and construction, including NRC review of the COLA, is measured in decades rather than years. According to NC WARN, Section 7 of Senate Bill 3, G.S. 62-110.7, allows recovery for the project development costs for a nuclear facility under certain conditions. Moreover, NC WARN states that G.S. 62-110.7 did not become effective until January 1, 2008, pursuant to Section 16 of the bill, and that no costs incurred for nuclear plant construction prior that date should be recoverable under any legal theory. NC WARN states that DEP witness Fallon testified that by the end of 2007 DEP had spent $13 million on the HNP, and he confirmed that this amount is the North Carolina jurisdictional share. (Tr. Vol. 12, p. 67).

NC WARN states that DEP did not apply to the Commission for a certificate of public convenience and necessity (CPCN) pursuant to G.S. 62-110.1 and opines that this step is crucial for cost recovery under G.S. 62.110(b). Without the CPCN, none of the costs spent are reasonable, according to NC WARN. Finally, NC WARN states that even when a CPCN is issued and construction has begun, and subsequently a plant is cancelled, the Commission is required to make a finding as to whether the plant is no longer in the public interest. NC WARN cites G.S. 62-1109(e), which states that:

> [o]nce the Commission grants a certificate, no public utility shall cancel construction of a generating unit or facility without approval from the Commission based upon a finding that the construction is no longer in the public interest.

NC WARN states that the prudency of the costs incurred was the principal issue in the 1988 Harris Order discussed by DEP witness Wright. (Tr. Vol. 21, p. 32) NC WARN states that the Commission conducted a prudency audit of costs associated with major equipment purchases and construction for the multiple cancelled units, and that unlike the present case, the first round of Harris construction was made pursuant to a CPCN, and that the one unit currently operating was credibly found to be used and useful. State ex rel. Utilities Commission v. Thornburg, 325 N.C. 484, 385 S.E.2d 463 (1989) (Thornburg II).

In conclusion, NC WARN asserts that the Commission should find that none of the costs associated with the predevelopment and COLA preparation for the Harris nuclear expansion project should be borne by ratepayers.

The Commission disagrees with NC WARN on this issue as it does not believe that the utility should have to bear the entire amount of costs associated with predevelopment and COLA preparation for the HNP since the facility was originally planned to be for the benefit of DEP's customers and subsequently was cancelled due to the HNP no longer being the best option. The Commission is of the opinion that just and reasonable rates result by the utilization of the eight-year amortization period agreed to in the Stipulation. By amortizing, or spreading the costs, over eight years, the ratepayers are not bearing the entire cost in rates today. The Commission further concludes that the costs of development of a generation plant for the use of a utility's customers should be recoverable if deemed prudent by the Commission. The Commission deems the costs related to the Harris COLA prudent, given the facts and circumstances discussed in the record. Therefore, NC WARN's position is not accepted.

For all of the reasons cited above and considering all of the evidence presented, the Commission finds that the costs of the Harris Site Development should be recovered consistent with the Stipulation, as the Commission concludes that this provision of the Stipulation is just and reasonable.

Customer Connect Program

DEP witness Fountain testified that DEP has extracted all of the value it can obtain from its current customer information system (CIS), which is over 30 years old. He stated that customers expect more and quicker access to information about their account and that replacing the present CIS will be more cost-effective than attempting to upgrade it.

DEP witness Hunsicker testified that the CIS manages DEP's billing, accounts receivable, and rates, and that it is the central repository for customer information. She explained that the current CIS was designed to communicate with the meter located at the premise, and not as a customer information storage or retrieval tool. Thus, the current CIS has limitations in accessing customer account history and other information, and in opening, closing, or transferring customer accounts, especially between DEP and DEC. Another limitation is that the current CIS does not record a bill credit. Thus, bill credits for net metering customers must be manually recorded. Witness Hunsicker further testified that investments to modify and upgrade the current CIS would not be practical or sustainable. She stated that a new CIS will provide numerous benefits, including quicker and simplified procedures for accessing customer information and serving customer's needs; improvements in bill formats; easier integration of new rate structures; and flexibility in implementing Advanced Metering Infrastructure (AMI) meters.

Witness Hunsicker testified that DEP will begin analysis and design of the new CIS, called Customer Connect Program (CCP), in January 2018, and that it plans to have the new CCP in service in 2021. The total cost will be approximately $155 million. DEP is requesting that the anticipated costs to be incurred from 2018 through 2020, $10.6 million per year, be included in its new rates.

In supplemental testimony filed on September 15, 2017, DEP witness Laura Bateman adjusted the annual revenue requirement for the CCP to reflect a reduction of $146,000.

Public Staff witness Floyd testified that the Public Staff does not agree that the costs of analysis and design of DEP's new CCP should be included in DEP's current rates. He stated that such costs do not meet the "used and useful" utility plant test in G.S. 62-133(b)(1), and, therefore, the Commission should disallow the costs.

DoD/FEA witness Cannady testified that the CCP costs should not be recovered by DEP in this rate case because: (1) they are not known and measurable, and (2) the CCP is a component of smart grid and should be evaluated for reasonableness and prudency at the same time as AMI and other smart grid projects.

In rebuttal testimony, witness Hunsicker responded to the Public Staff's position that the costs of the CCP should be disallowed because it will not be used and useful until it is fully operational in the summer of 2021. She testified that DEP is requesting rate recovery of the O&M needed to build the CCP, or, in the alternative, a deferral of the O&M so that it can be recovered in a future rate case. She further testified that DEP will employ a phased approach that will result in some of the CCP functions being available and beneficial to customers in 2018. These include the "360 degree view" feature that will use customer contacts with DEP over social media, voice mail, and web sites to improve DEP's ability to communicate with its customers.

In addition, witness Hunsicker disagreed with DoD/FEA witness Cannaday's position that the costs of the CCP are not known or measureable at this stage. She stated that DEP has entered into fixed price contracts for a significant portion of the CCP, including software, system integrator professional services, and training.

In its post-hearing Brief, EDF contends that the Commission should not grant DEP's request to recover costs for its CCP because: (1) the CCP will not be used and useful within a reasonable time after the test period, (2) even if some portion of the CCP were available within a reasonable time after the test period, the limited functionality is not worth the amount DEP seeks to recover, and (3) DEP has failed to manage the CCP project efficiently to maximize customer benefits arising from access to energy usage data.

With regard to whether the CCP will be used and useful, EDF states that DEP's planned in-service date of 2021 is merely a target date and DEP can offer no assurances that the CCP will actually be in service in 2021.

With respect to limited functionality, EDF contends that DEP offered no evidence regarding the precise new services customers would receive from the CCP, how much customers would benefit from these new services, or whether the same services could be provided manually. Moreover, EDF maintains that DEP has the burden of proof to identify and establish the precise new services the CCP will perform, when the new services will be available, and how the new services will benefit customers, and that DEP failed to meet its burden of proof on these issues.

With regard to EDF's assertion that DEP has failed to manage the CCP project efficiently, EDF states that DEP has failed to efficiently manage the project by failing to analyze how Green Button Connect could be used to maximize the benefits customers would receive from enhanced access to energy usage data.

In the Stipulation, DEP and the Public Staff agreed that the CCP will be removed from DEP's revenue requirement. However, DEP will be authorized to establish a regulatory asset to defer and amortize the CCP costs. The regulatory asset account will accrue AFUDC until the DEP Core Meter-to-Cash release (Releases 5-8) of the CCP project goes into service or January 1, 2022, whichever is sooner. At that point, the costs will be amortized over 15 years. In addition, DEP will be required to file reports regarding the development of the CCP each year on December 31 for the next five years or until the CCP is fully implemented, whichever is later.

The Commission finds and concludes that the Stipulating Parties' agreement with regard to the CCP is a just and reasonable path forward to allow DEP to develop its CCP, and to defer the costs of the program until there is a used and useful component of the CCP implemented, that being the Core Meter-to-Cash component. This resolves the most substantial concern expressed regarding the CCP. In addition, the other substantial concern – that the costs of the CCP are not known or measurable at this stage – is resolved by placing the costs in a deferred account, thereby making the costs subject to review in a subsequent proceeding. As a result, the Stipulating Parties' agreement with regard to the CCP should be accepted.

<u>Customer Usage Data</u>

In his direct testimony, NC Justice Center witness Howat testified that questions regarding the effectiveness of existing regulatory consumer protections and credit and collection practices can only be answered through data-driven analysis of trends in customer arrearages, service disconnections, and related indicators of the magnitude of utility payment troubles. Witness Howat further testified that monthly reporting of such data is crucial for ongoing assessments of the state of home energy security among DEP's residential customers and for evaluating the effectiveness of programs and policies intended to protect that security. (Tr. Vol. 13, pp. 258-59.) Witness Howat recommended that DEP collect and make publicly available, on a monthly basis and in readily accessible spreadsheet format, numerous data points by zip code. Further, he contended that many utilities in the United States regularly report such information, including those in Ohio, Illinois, Pennsylvania, and Iowa. (Tr. Vol. 13, pp. 260-64.)

In her rebuttal testimony, DEP witness Hunsicker responded to witness Howat's recommendation that DEP be required to collect, report by zip code, and make publicly available data regarding residential customer billings, receipts, arrearages, notices of disconnection, uncollectibles, and similar information that is specific to low-income residential customers. Witness Hunsicker testified that DEP disagrees with this recommendation for three reasons: (1) DEP presently complies with all of the

Commission's requirements for customer data collection and retention, (2) DEP would be required to collect more customer information than it presently collects and stores, and (3) witness Howat's recommendation would create privacy concerns regarding sharing of customer data. She further noted that DEP does not currently obtain data, such as income level, that would enable it to distinguish between low-income and middle- or upper-income customers.

In its post-hearing Brief, NC Justice Center states that according to DEP the Company's existing CIS "does not enable ready access to account histories that can be important in non-pay situations" (Tr. Vol. 9, pp. 191-92), but that DEP's new CCP will be fully integrated into DEP's other systems and will include the ability to interface with new smart meters and automate complex billing functions. (Tr. Vol. 9, pp. 144-45.) NC Justice Center urges the Commission to require that DEP, upon installation of its new CCP, develop and implement a data collection and reporting protocol to regularly collect and report data related to customer energy usage and demographics, consistent with the recommendations of witness Howat, and that the Commission Staff should conduct a public technical session with DEP and interested stakeholders during the design phase of the data collection and reporting protocol in order to ensure that resulting reports are of benefit to all parties.

NC Justice Center further states that the National Association of Regulatory Utility Commissioners (NARUC) and the National Association of State Utility Commission Advocates (NASUCA) have adopted resolutions calling for the collection and reporting of precisely the types of information recommended by witness Howat, and notes that DEP witness Hunsicker stated that DEP does not disagree with the goals cited by NARUC and NASUCA. (Tr. Vol. 9, pp. 209-10, 212-13.)

The Commission appreciates the recommendation of NC Justice Center that DEP be required to regularly collect and report data related to customer energy usage and demographics once DEP's CCP is operational. However, the Commission is not persuaded that this is the time or the proceeding in which to impose such requirements on DEP. The Commission is addressing issues regarding access to customer usage data in Docket No. E-100, Sub 147. In addition, DEP has not initiated a full deployment of AMI, which could be another resource for collection and reporting of the data that NC Justice Center seeks to require DEP to collect and report. The parties and Commission will know more about the availability of such data, and the cost of collecting and reporting it, once the CCP and AMI are implemented. As a result, the Commission declines to adopt NC Justice Center's proposal at this time.

<u>Deprecation Rates</u>

Company witness Doss introduced Doss Exhibit 4, the Depreciation Study which was prepared by Gannett Fleming Valuation and Rate Consultants, LLC. (Tr. Vol. 10, p. 3.) As explained by witness Doss, the Depreciation Study included updates to estimates of final plant decommissioning costs for steam, hydraulic, and other production plants, as well as updated forecasted generation plant retirement dates. (<u>Id.</u> at 17.) In addition, witness Doss introduced Doss Exhibit 5, the Decommissioning Cost Estimate Study prepared by Burns and McDonnell, an external engineering firm. This report included estimates for final decommissioning costs at steam, hydraulic, and other production plants.

As witness Doss explained, the depreciation rates for various fossil and hydro plants were also updated due to changes in the probable retirement dates. The probable retirement dates were updated primarily to align dates with current licenses, industry standards, or operational plans due to aging technology, assumptions for future environmental regulations, or new planned generation. (Tr. Vol. 7, p. 72.) The Depreciation Study also incorporates generation assets placed in service since the last study. Finally, the average service life and net salvage assumptions were updated for various distribution, transmission, and general plant assets. (Tr. Vol. 10, p. 88.)

The Stipulating Parties have agreed that the Company's depreciation rates will be set based on the rates set forth in the Company's most recent depreciation study, subject to the following inputs: (1) a 10% contingency; (2) a 10-year remaining life for the meters that are being retired pursuant to the Company's AMI program; (3) a 70-year R2 curve (70-R2) for Account 356; (4) a negative 10% net salvage for Account 366; (5) a 17-year life for new AMI meters; and (6) a 20-year amortization period for Accounts 391 and 397. The record in this case supports the utilization of the Company's most recent Depreciation Study as the basis for setting depreciation rates as amended by the Stipulation. A discussion of the specific issues related to depreciation, as addressed by the various witnesses, is presented below.

Contingency

The Company's Decommissioning Cost Estimate Study prepared by Burns and McDonnell included a 20% contingency to cover unknowns. Witness Kopp explained that a contingency cost is included in the Company's Decommissioning Study to account for unspecified, but reasonably expected additional costs to be incurred by the Company during the execution of decommissioning and demolition activities. (Tr. Vol. 12, p. 169.) Indeed, witness Kopp explained that costs incurred by the Company for the decommissioning and demolition of Cape Fear, H.F. Lee, Sutton, Robinson, and Weatherspoon plants were actually 11% higher than forecasted by the Burns and McDowell Decommissioning Study completed in 2012 for DEP. (Id. at 11.) Public Staff witness McCullar recommended a 0% contingency, expressing concerns that the contingency factor is an uncertain cost in the future that DEP has not specifically identified. (Tr. Vol. 7, pp. 266-67.) Witness Kopp expressed concern over witness McCullar's position because it "misrepresents the purpose of inclusion of contingency in the estimates . . . . [C]ontingency represents costs that are reasonably expected to be incurred, [and] these costs were actually incurred by the Company on projects that have been commissioned to date." (Tr. Vol. 12, p. 176.)

Witness McCullar also expressed concern that "inclusion of contingency costs inappropriately puts all the risk of the future unknown, unidentified costs on the current ratepayers." (Tr. Vol. 12, p. 179.) Witness Kopp disagreed due to the fact that the costs are anticipated to be incurred costs, and that recent experience by the Company has shown that it is reasonable to expect to incur these costs. (Tr. Vol. 12, p. 179.) Although DEP and the Public Staff held opposing views on this issue, both parties have stipulated regarding this issue. Similarly, Fayetteville PWC witness Hughes argued for a 10% contingency factor to be applied to direct costs to cover unknowns. (Tr. Vol. 7, pp. 206-07.) Witness Hughes' recommendation is based on the fact that the 10% contingency factor is equal to the contingency factor used in the 2010 Depreciation Study to develop rates in DEP's last rate case. (Tr. Vol. 7, pp. 207-08; Tr. Vol. 12, p. 179.) As explained by witness Kopp, the prior Decommissioning Study also included a 20% contingency. (Tr. Vol. 12, p. 180.)

As the result of a settlement in the last case, the contingency was reduced. (Id.) However, witness Kopp explained that a 20% contingency is reasonable and appropriate for the decommissioning cost estimates, stating, "[T]he Company's experience with actual demolition costs in total on five recent projects has exceeded the BMcD estimate in total for these five projects." (Id.) Although witness Kopp cautioned that a 10% contingency could put risk on future ratepayers, the issue was stipulated utilizing a 10% contingency. (Id.)

In light of all of the evidence, the Commission finds and concludes that the contingency factor agreed to by the Stipulating Parties is reasonable and appropriate for use in this case.

70-R2 for Account 356

DEP proposed a 65-year R2.5 curve for Account 356, Overhead Conductors and Devices. (Tr. Vol. 7, p. 285.) Company witness Spanos explained that most estimates in the industry for Account 356 have service lives of 65 years or less, as opposed to Fayetteville PWC and Public Staff estimates of 70 years or longer. (Tr. Vol. 12, pp. 146-47.) Public Staff witness McCullar recommended an R2-70 curve for Account 356. (Tr. Vol. 7, pp. 281-82.) Witness McCullar based this view on more recent life experience bands of 1977-2016. (Id. at 285.) Public Staff witness McCullar stated that DEP proposed an increase in life from 60 years to 70 years in its June 28, 2013 Depreciation Study. (Tr. Vol. 7, p. 286.) Witness McCullar also stated that "[t]he Public Staff' proposed 70-year R2 curve shape is a better fit to the actual observed life data" upon which DEP based its proposal for this account. (Tr. Vol. 7, pp. 286-87.) The Public Staff and the Company have agreed as Stipulating Parties to a 70-R2 curve for Account 356.

The only other witness making a recommendation on Account 356 was Fayetteville PWC witness Hughes. Witness Hughes recommended an R2-72 survivor curve for Account 356. (Tr. Vol. 7, p. 201.) Witness Hughes asserted that the R2-72 survivor curve provides a better fit to the actuarial data than DEP's R2.5-65 curve. (Id.) According to witness Hughes, "[t]he SSD for the R2-72 curve is equal to 0.68, which is much lower (better) than the 2.76 SSD for DEP's proposed R2.5-65 survivor curve." (Tr. Vol. 7, p. 201.)

Witness Spanos, however, explained that witness Hughes' analysis of mass property service lives is over-simplistic and lacks reasonable judgment. As explained by witness Spanos, service lives are estimated for mass property accounts using established survivor curves, which provide an estimate of both an average service life and a dispersion of lives around the average. (Tr. Vol. 12, p. 137.) The process for estimating service lives is based on informed judgment that incorporates a number of factors, including statistical analysis of historical data. (Tr. Vol. 12, p. 145.) Witness Spanos also testified that other factors considered should include the mortality characteristic of the property studied and Company-specific information. (Tr. Vol. 12, p. 145.) Witness Spanos testified that these factors support his estimate over that of witness Hughes, as his estimate forecasts that the overall level of retirements for accounts will tend to increase with age:

> This is a reasonable expectation for substation equipment. Retirements of assets in this account, such as transformers and circuit breakers, tend to increase with age as older assets are more subject to failure and to needing to be replaced for capacity reasons. In contrast, the expectation inherent to witness Hughes' estimate that retirements will not tend to increase with age is less reasonable for this account.

(Tr. Vol. 12, p. 145.)

All three experts in this proceeding utilized the retirement rate method for their statistical analyses. According to witness Spanos, witness Hughes incorrectly overemphasized the tail of the data by putting unnecessary emphasis on the final 20% of the life of the asset. (Tr. Vol. 12, pp. 142-43, 192-97.) As witness Spanos explained, witness Hughes' analysis lacked the judgment that is also required in properly determining the appropriate survivor curve. (Tr. Vol. 12, p. 194.) Witness Spanos testified that it is not appropriate to focus on the tail of the curve because the data points for these older ages can also be erratic and not indicative of the mortality characteristics for the account, and that the overreliance on mathematical matching without the accompanying judgment was pervasive throughout witness Hughes' analysis of mass property accounts. As witness Spanos went on to explain, there are authoritative texts that support the concept that information in the middle years of the curve is where the emphasis should be placed. (Tr. Vol. 12, p. 142-43.) This analysis is based on the probable error involved in fitting a smooth survivor curve to an observed life table with varying percentages surviving:

> When survivor curves are to be classified according to the 18 types and the probable average life to be determined, it is recommended that more weight be given to the middle portion of the survivor curve, say that between 80 and 20% surviving, than to the forepart or extreme lower end of the curve. This inner section is the result of

> greater numbers of retirements and also it covers the period of most likely the normal operation of the property.

(Id.)

As discussed previously, both witness McCullar and witness Spanos utilized the same statistical method and came to different conclusions than did witness Hughes for Account 356.

In light of all of the evidence, the Commission finds and concludes that utilization of the R2-70 curve proposed by the Stipulating Parties is reasonable.

Negative 10% net salvage for Account 366

Public Staff witness McCullar quoted as follows from the NARUC publication Public Utilities Depreciation Practices, p. 18 (1996):

> Positive net salvage occurs when gross salvage exceeds cost of retirement, and negative net salvage occurs when cost of retirement exceeds gross salvage.

(Tr. Vol. 7, p. 275.) Further, witness McCullar testified that:

> 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 the Company may incur associated with plant asset's retirement.

(Id.)

The Depreciation Study filed by DEP in this case supported a future net salvage value of negative 15% for the Mass Property Distribution Account 366, Underground Conduit. As explained by witness Spanos, the DEP's Depreciation Study utilized the traditional method of calculating net salvage which is relied upon by the vast majority of regulatory commissions in the United States. (Tr. Vol. 12, pp. 98-99, 111.) The traditional method meets the requirements of FERC Uniform System of Accounts and has been used for several decades in North Carolina. (Id.). The Company method is also endorsed widely by authoritative depreciation texts and is accepted in the industry. (Id.; Tr. Vol. 12, p. 124.)

Witness Spanos explained the traditional method of calculating net salvage as follows: "When using the traditional method, net salvage is estimated as a percentage of the original cost of plant. The statistical analysis used in estimating net salvage is based on comparing historical, not just recent, net salvage expenditures to historical retirements." (Tr. Vol. 12, pp. 98-99.)

Witness Spanos stated that DEP considered multiple factors in estimating the future net salvage percent:

> The estimates of net salvage by account were based in part on historical data compiled through 2016. Cost of removal and salvage were expressed as percents of the original cost of plant retired, both on annual and three-year moving average bases. The most recent five-year average also was calculated for consideration. The net salvage estimates by account are expressed as a percent of the original cost of plant retired.

(Tr. Vol. 7, p. 279.)

In addition, witness Spanos testified that the traditional methodology "provides a reasonable basis for net salvage estimation because the amount of net salvage expended in a given year is a function of the number of assets retired in that year." (Id.)

Public Staff witness McCullar proposed a negative 5% net salvage value for Account 366. Witness McCullar testified that for some accounts the annual accrual amount that would be accrued for estimated net salvage is several times the annual amount the DEP actually incurs for net salvage. (Tr. Vol. 7, p. 278.) Witness McCullar also considered historical net salvage data included in the 2016 Depreciation Study as well as the inflation rate included in DEP's proposed net salvage values. (Tr. Vol. 7, pp. 279-80.) Company witness Spanos testified the Public Staff's method does not allocate the service value of depreciable property in a systematic and rational manner.

Moreover, DEP witness Spanos expressed concerns that the Public Staff's proposal is effectively to allocate only an amount equal to the net salvage costs that have been incurred in the past. "It does not incorporate the future net salvage costs for assets that are currently in service and, therefore, does not allocate the service value of depreciable property over its service life." (Tr. Vol. 12, p. 110.) Witness McCullar's approach is also not supported by various authoritative texts on depreciation, addressing the issue of whether net salvage should be accrued during the life of the related plant. (Tr. Vol. 12, pp. 121-23.)

Ultimately, the Public Staff and the Company agreed to a negative 10% net salvage value for Account 366, which is consistent with the currently approved net salvage value for Account 366. In light of all of the evidence, the Commission finds and concludes that a negative 10% net salvage value proposed by the Stipulating Parties is reasonable based on the evidence presented in this case.

20-year amortization period for Accounts 391 and 397

DEP proposed in this case to move several general plant accounts to amortization accounting. (Tr. Vol. 7, p. 288.) General plant amortization accounting is used for general plant accounts that include a large number of units with relatively low unit cost.

Amortization accounting is used because the cost of tracking retirements for every single asset typically exceeds the benefit of doing so. (Tr. Vol. 12, p. 152.) Witness McCullar also noted that "[t]he use of amortization accounting for these smaller value general plant accounts is used to minimize the accounting expense involved in keeping the detailed records used in depreciation accounting." (Tr. Vol. 7, pp. 288-89.) No party presented testimony opposing the Company's move to amortization accounting. (Tr. Vol. 12, p. 153.) Opposing testimony was only presented regarding the appropriate amortization periods for certain accounts, as well as the reserve adjustment for amortization accounting. (See, e.g., Tr. Vol. 7, p. 289; Tr. Vol. 12, p. 153.)

DEP determined the amortization periods to be used as follows:

> The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization periods and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

(Tr. Vol. 7, pp. 289-90.)

For Account 397, the Company is proposing a 10-year life for amortization accounting. Public Staff witness McCullar argued that the amortization period proposed by the Company for Account 397, Communication Equipment, among others, is not based on the service life estimates previously used for the asset under depreciation accounting. (Tr. Vol. 7, p. 290.) Witness McCullar further argues that there is no historical data to back up the Company's recommendation. (Id. at 291.) Witness McCullar recommended a 20-year life for Account 397 based on the 15- to 20-year range and the actual DEP experience that indicates a 25- to 29-year life. (Id.) In addition, witness McCullar recommended a 20-year life for Account 391, Office Furniture and Equipment, as opposed to the Company's 15-year recommended amortization period. (Id. at 292.)

In response, Company witness Spanos testified that relying on the historical analysis for amortization accounts is often unreliable due to the nature of the assets in these accounts, in where there are many units with small dollar values that are difficult to track. (Tr. Vol. 12, pp. 152-53.) Furthermore, statistical life analyses often produce indications of too long of lives because retirements are not always recorded. (Id.). Second, witness Spanos notes that witness McCullar's proposal fails to take all equipment depreciation into account, which would result in a lower overall average. (Id.) Witness Spanos stated that the Commission has approved a 10-year life for DEC for this account, and opined that the same is reasonable for DEP. (Tr. Vol. 12, pp. 152-53.)

Fayetteville PWC witness Hughes did not oppose the use of amortization accounting, nor challenge the amortization periods requested by the Company, but instead challenged the Company's proposal to use a 5-year amortization period to recover the cost of assets that are retired because they are older than the amortization period for each account. (Tr. Vol. 7, pp. 214-16.) Witness Hughes recommended a 10-year amortization period for these items. (Tr. Vol. 12, pp. 154, 214-16.)

In response to witness Hughes, witness Spanos explains that the 5-year period to amortize the unrecovered reserve is appropriate. (Tr. Vol. 12, p. 154.) Because the unrecovered reserve is associated with existing assets, it is more reasonable to align the recovery of these costs with the remaining lives of the assets currently in service, rather than the proposed amortization periods as witness Hughes suggested. (Id.) The remaining lives of Accounts 391 (which has two subaccounts) and 397 are 6.8, 4.8 and 5.1 years. (Tr. Vol. 12, p. 154.) Therefore, the remaining lives for these accounts are closer to the Company's 5-year amortization period than the 10-year period proposed by witness Hughes. (Id.)

The Stipulating Parties have agreed as part of the settlement to the 20-year amortization period for Accounts 391 and 397. In light of all of the evidence, the Commission finds and concludes that a 20-year amortization period for Accounts 391 and 397 proposed by the Stipulating Parties is reasonable in this case. The Commission further finds that witness Hughes' proposal to adjust the unrecovered reserve is not appropriate and should not be adopted.

Other Depreciation Recommendations

1. Generation Retirement Dates

In addition to the specific areas of the Stipulation discussed previously, Fayetteville PWC witness Hughes also recommended adjustments to generation plant and interim net salvage for Account 343, Prime Movers. Witness Hughes recommended adjusting the life span of Roxboro Units 1-4 and Blewett combustion turbines so that the life spans would match the Integrated Resource Plan Study filed with the Commission on September 1, 2016. (Tr. Vol. 7, pp. 188-89.) Witness Hughes expressed the belief that the estimated retirement years for generation plant used in the Depreciation Study should be consistent with the lives the Company uses for its generation resource planning. (Id.)

In rebuttal, Company witness Miller explained that witness Hughes' adjustment was not appropriate. The difference between the retirement dates in the Company's recently completed Depreciation Study and the retirement dates in the Company's 2016 and 2017 IRPs is simply due to timing. (Tr. Vol. 10, pp. 36, 49). The retirement dates in the Company's IRPs are based on the most recently approved depreciation study. (Id. at 49.) The retirement dates for Roxboro and Blewett that witness Hughes relies upon were taken from the last approved depreciation study performed in 2010. (Id.) The Company completed the current Depreciation Study in 2017 and included it for Commission approval in this rate case. (Id. at 53.) Once the current Depreciation Study is approved, the next IRP will reflect the approved dates. (Id. at 49.) "Further," stated witness Miller, "depreciation study dates do not signify a commitment to retire." (Id.) Although witness Hughes argued that DEP's power plant engineers, power supply planners, and management should be responsible for determining the estimated retirement years for generation units and not the depreciation analyst (Tr. Vol. 7, p. 190), her testimony fails to acknowledge that witness Spanos and his team from Gannett Fleming visited several plant locations, including Blewett and Roxboro. (Dep. Study, p. III-2.) Gannett Fleming also conducted interviews with management to go over current Company policies and outlook for the plants. As witness Miller explained, Central services/engineering group specifically provided input to Gannet Fleming on generating retirement dates.

Fayetteville PWC witness Hughes testified that she believed DEP's proposal to divide Account 343 into subaccounts and impose an interim net salvage for a non-rotable parts subaccount of negative five percent (-5%), DEP's proposed survivor curves for Accounts 352 through 356, and DEP's practice of allowing the remaining useful lives of its generating units to be set in its depreciation rate studies rather than in its integrated resource planning are all inherently unreasonable and should be rejected in favor of the recommendations set forth in her testimony. The Commission disagrees with the recommendation by Fayetteville PWC witness Hughes, as deprecation studies delve into the details of the accounts and are the proper forum for useful lives to be set or reset. The Commission agrees, however, that the IRP is a tool that should be reviewed and utilized when performing the deprecation study and determining useful lives of assets. Based on the foregoing discussion, Fayetteville PWC's position is not accepted. Rather, the record supports a determination that the 2017 Depreciation Study performed by Gannet Fleming contains the most up-to-date and accurate estimated life spans for the Company's plants and should be relied upon in this case for setting depreciation rates.

2. Account 343, Prime Movers

DEP proposed negative five percent (-5%) interim net salvage value for Account 343, Prime Movers. (Tr. Vol. 7, p. 209.) DEP proposed to segregate Account 343 into two subaccounts for combined cycle plants in this case. (Id.) One of the segregated accounts will include "rotable parts," which have a relatively short service life and a high positive salvage. This is because these components, such as turbine blades and transition components of combustion turbines, are replaced at regular intervals and refurbished. (Id.)

Fayetteville PWC witness Hughes testified that she characterizes the division as experimental because (i) there is no such division in the Code of Federal Regulation's Account 343 for rotable and non-rotable parts, and (ii) DEP's proposal deviates from DEP's existing Commission-approved accounting practice of recording Account 343 items on a consolidated basis. Witness Hughes stated her concern that DEP has no actual data to support its proposed negative five percent (-5%) interim net salvage for the proposed non-rotable parts subaccount. Company witness Spanos testified to as much stating that "At this time, there is not. One of the reasons for the new subaccounts is so that net salvage can be tracked separately for the two subaccounts." (Tr. Vol. 12, p. 135)

In addition, witness Hughes testified that she does not recommend any changes to the proposed net salvage rate for Account 343.1, Prime Movers – Rotable Parts. (Tr.

Vol. 7, p. 211.) However, she proposed interim net salvage of zero percent for non-rotable parts as compared to the Company's negative 5% "until there is sufficient data to track the net salvage for the subaccounts separately." (Tr. Vol. 7, p. 209.) In witness Hughes' opinion, there is insufficient data to track the net salvage for the subaccounts separately. (Tr. Vol. 7, pp. 211-12.) Although witness Spanos acknowledged that no historical data exists that can be used to estimate the net salvage specific to non-rotable parts (Tr. Vol. 7, p. 212; Tr. Vol. 12, p. 135), his testimony made clear that assigning a value of 0% to this subaccount is also inappropriate.

The overall historical data, which is shown on page VII-39 of the Depreciation Study, indicates an overall positive level of net salvage, but that is only part of the analysis. (Tr. Vol. 12, pp. 135-36.) The data also consistently shows a cost of removal associated with the retirements in the past ten years. As witness Spanos explained, almost all of the gross salvage is associated with the rotable parts, and, therefore, there should be a negative net salvage estimate for non-rotable parts. (Id.) He stated that witness Hughes' recommendation does not make sense: "[T]here is typically a cost to remove components from a power plant, and for this reason there should be some negative net salvage." (Id.) In addition, witness Spanos presented a utility example that supported assigning a negative value to non-rotable parts. (Id. at 136.)

The Commission finds that witness Hughes' proposal to assign a interim net salvage value of zero percent for non-rotable parts for Account 343, Prime Movers, should not be adopted at this time. The Commission finds Company witness Spanos' argument has merit in that there is typically some cost associated with the removal of power plants. Additionally, the Commission finds Company witness Spanos' utility example supportive of assigning a negative value to non-rotable parts. Furthermore, the record supports assigning a negative value to this subaccount, and the amount proposed by witness Spanos is reasonable in light of the evidence presented and should be approved.

3. Requirement of Workpapers

Witness Hughes states that the Company "should be required in future rate cases to develop and provide workpapers to support the calculation of the projected total interim retirements." (Tr. Vol. 7, p. 205.) Witness Spanos disagrees:

> [T]here are no specific workpapers that can be provided related to these calculations. The projected interim retirements are calculated by iteratively applying the retirement ratios from each recommended interim survivor curve to the plant balance for each year from the current date to the retirement of the Company's power plants. Because there are numerous calculations involved in this projection, the calculations cannot be performed in a spreadsheet or any other worksheet, and instead are performed with depreciation software. As a result, there are no workpapers available. Instead, the

> resulting calculated amounts are used in workpapers that have already been provided through discovery.

(Tr. Vol. 12, pp. 136- 37.)

The Commission agrees that if the calculations are indeed iterative, as stated by the Company's deprecation witness Spanos, there would be no real workpapers to provide. Iterative calculations are numerous and cannot be produced effectively on spreadsheets, as they are calculations that are performed by the computer behind the scenes. Based on the aforementioned reasons and all of the evidence in the record, the Commission, therefore, finds and concludes that witness Hughes' recommendation to develop and provide workpapers to support the calculation of the projected total interim retirements in future rate cases should be rejected.

4. CIGFUR Recommendation

CIGFUR witness Phillips recommended that any approved changes to depreciation rates net to a zero-dollar impact on the level of depreciation expense included in rates. (Tr. Vol. 7, p. 73.) He further recommended that that customers not be burdened at this time by the impact of shortening service lives of generating lives based upon assumptions about changing and evolving environmental regulations. (Id.)

As 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. 12, p. 155.) He offered no credible critique of the Company's filed Depreciation Study and provided no alternative analysis. The current Depreciation Study as modified by the Stipulating Parties demonstrates that current depreciation rates are insufficient and that adjustments are necessary to ensure recovery of the full cost of the Company's assets providing service to DEP customers. (Tr. Vol. 12, p. 155.)

CIGFUR witness Phillips also incorrectly asserts that depreciation rates have changed due to changes to life spans as a result of environmental regulation. As witness Spanos points out, that is incorrect as there are a variety of reasons that depreciation rates change over time as evidenced by the comprehensive Depreciation Study filed in this case. The depreciation study includes all of the Company's assets, and changes in depreciation rates occur for many reasons, including updated historical data, updated service life and net salvage estimates, and additions to generating facilities. The current depreciation study is based on the available information regarding the Company's assets, and the depreciation rates therefore need to be updated to reflect current circumstances. (Tr. Vol. 12, p. 156.)

For the foregoing reasons, CIGFUR witness Phillips' blanket recommendation regarding depreciation rates is rejected.

In the Stipulation the parties agreed that the Company's depreciation rates should be based on the rates set forth in the Company's most recent Depreciation Study, subject to application of the following inputs: (1) a 10% contingency; (2) a 10-year remaining life for the meters that are being retired pursuant to the Company's AMI program; (3) 70-R2 for Account 356; (4) a negative 10% future net salvage for Account 366; (5) a 17-year life for new AMI meters; and (6) a 20-year amortization period for Accounts 391 and 397. The Commission finds and concludes that in light of all of the evidence presented in this case, that the agreed upon methods and procedures are appropriate for use in this proceeding.

End of Life Nuclear Materials and Supplies Reserve

DEP requested that the Commission adjust the reserve and annual amortization expense based on a review of current reserve requirements. The original Company proposal included an accrual and uses the 20% factor which was used in the 2013 Rate Case. (Tr. Vol. 6, p. 121.) Witness Bateman provided initial testimony in support of the adjustment. (Id.) Materials and supplies (M&S) inventory are often unique and specific to individual plants and have minimal value, if any, to other plants. The accrual amount was determined by dividing the projected inventory balance at the end-of-life (EOL) of each unit by the number of years remaining in the unit's life.

The Company has accepted the Public Staff's adjustment to the end-of-life nuclear M&S reserve expense, reduced as described in the rebuttal testimony of Company witness Gillespie. Per the Stipulation, the Company agreed to take appropriate action to manage its M&S inventory to the current practices and procedures utilized by DEC, with the goal to ensure that proper levels of inventory are on hand within 24-months after the entry of the Commission's rate case order.

Public Staff witness Metz testified that the Commission should adopt a $12.4 million adjustment to DEP's M&S inventory at its nuclear generation sites. (Tr. Vol. 7, pp. 308-13.) Witness Metz reviewed DEP's recorded nuclear plant M&S inventory and performed a field audit of the Harris Nuclear Plant. Witness Metz discovered categories of inventory items that existed in a "hold" status for over four years, which results in excess or unusable inventory. The "hold" categories include: Repair Hold, QA Hold, and Engineering Change Hold. The QA Hold category includes two subcategories: Quality Hold and Quality Pending. Witness Metz described these "hold" categories as reasonable and commonly used in the industry. Witness Metz recommended that the Commission exclude QA and Repair Hold that has been held for greater than four years (total $12.4 million). According to witness Metz, hold times exceeding four years indicates that the Company may never resolve the issues, which results in the Company never using the associated inventory. (Id. at 313.) Witness Metz did not include the Engineering Change Hold category costs in the adjustment, explaining that delays may occur for certain projects due to the need to balance and minimize the overall outage schedule. (Id.)

Witness Cannady testified that the Commission should not increase the Company's annual accrual for EOL nuclear M&S inventory. (Tr. Vol. 17, p. 163.) Witness Cannady argues that DEP failed to demonstrate that the M&S inventory levels are necessary to provide service up to the EOL of each nuclear facility: the Company provided no documentation supporting that (1) the test year EOL levels are reasonable or (2) that the levels must be met through annual accruals to an EOL reserve. (Tr. Vol. 17, p. 176.) Witness Cannady also questions the 20% transferability and salvage value factor used in the DEP accrual calculation. (Tr. Vol. 17, p. 136.) Accordingly, witness Cannady recommends that the Commission not grant additional accrual of $7.435 million, resulting in a $4.7 million increase in operating income.

Witness Gillespie filed rebuttal testimony in response to witnesses Metz and Cannady. (Tr. Vol. 7, pp. 44-52.) Witness Gillespie testified that it is appropriate to include Repair Hold and QA Hold for more than four years. Such items are stored and maintained in a manner that would support the eventual repair and reuse of the item. (Tr. Vol. 7, pp. 47-48.) Categories of inventory on Repair Hold include those that can be repaired on-site or at other DEP facilities and items sent to external vendors for repair. (Id. at 48.) Generally, items on QA Hold for greater than four years indicate that efforts to resolve the deficiency with the vendor have concluded and additional engineering analysis by the Company is required. As with Repair Hold, the Company deploys its limited engineering resources to resolve the items on hold status based on overall priorities. The Company must use some resources for repair under both circumstances: internal labor or financial, in the case of off-site repairs. (Id. at 47.) Furthermore, the QA Hold and Repair Hold inventory levels as of December 31, 2016, are lower than the levels represented in witness Metz's testimony. (Id. at 49.)

In response to witness Cannady, witness Gillespie testified in support of the annual accrual for EOL nuclear M&S. Until removed from service, nuclear plants must be fully maintained for safety purposes, and inventory must be available to support that objective. Therefore, witness Gillespie explained, inventory currently necessary to support plant operations will be required until plant operations cease. (Id. at 50.) In the 2013 Rate Case, the Public Staff and DEP agreed that nuclear M&S inventory would be given a 20% value. Company witness Gillespie testified that the 20% salvage value estimate remains reasonable and appropriate. (Id. at 50-51.) The Company had no reason to believe that 20% transferability and salvage value established in the prior case would have increased.

As set forth in Section III.T. of the Stipulation, the Stipulating Parties agreed to include an adjustment to the nuclear M&S reserve and annual amortization expense. The Company agreed to take appropriate action to manage M&S (nuclear and non-nuclear) to the current practices and procedures utilized by the Company. The Company stated it will update the Commission within 24-months after the entry of the Commission's rate case order regarding the updated procedures and practices. Accordingly, the Commission finds and concludes that the recommended adjustment is just and reasonable to all parties considering all the evidence presented.

Asheville Plant

The Company requested that the Commission allow it to establish a regulatory asset at the time of the Asheville coal plant's retirement for the remaining net book value, and permission to defer to this regulatory asset any costs related to obsolete inventory, net of salvage, at the time of retirement. (Application at 11.)

DEP witness Bateman explained that originally the Company's depreciation consultant had proposed new depreciation rates that would fully depreciate the Asheville coal plant by its expected retirement date in 2020. (Tr. Vol. 6, p. 117.) In order to mitigate the impact on customers in this case, DEP asked the consultant to adjust the rates to reflect a recovery of the remaining net book value of the Asheville coal plant over a 10-year period, similar to the treatment of other coal plants that were retired early in DEP's prior depreciation study. (Id. at 117-18.) Since under this approach the net book value of the plant will not be fully recovered at the time of retirement, witness Bateman explained that the Company is requesting permission to establish a regulatory asset at the time of the plant's retirement for the remaining net book value and the ability to continue amortizing the costs over the remaining portion of the ten-year period at that time. (Id. at 118.) The Company also requests permission to defer to this regulatory asset any costs related to obsolete inventory, net of salvage, at the time of retirement. (Id.)

The Company's request was not contested by any of the intervenors. Therefore, the Commission finds and concludes that the Company's request to establish a regulatory asset related to the retirement of the Asheville coal plant is just and reasonable to all parties in light of the evidence presented. The Commission finds that the Company's request is appropriate and will mitigate the impact on customers. The Commission further concludes that the Company may establish a regulatory asset at the time of the Asheville coal plant's retirement for the remaining net book value and may defer to this regulatory asset any costs related to obsolete inventory, net of salvage, at the time of retirement.

EDIT Refund

In this proceeding the Company included an adjustment to amortize the excess deferred income tax (EDIT) that it deferred pursuant to the Commission's May 13, 2014 order in Docket No. M-100, Sub 138. In its Application, the Company proposed that the EDIT liability included in this case be returned to customers over a five-year period. Witness Peedin testified that the Public Staff believes that it would be beneficial to return the EDIT to customers through a rider that will expire at the end of a two-year period. (Tr. Vol. 18, pp. 79-80.)

In the Stipulation, the parties agreed that the EDIT liability should be returned to customers through a levelized rider that will expire at the end of a four-year period.

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

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16-24

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

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

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

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

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

- Order Granting General Rate Increase in the Company's previous Rate Case, Docket No. E-2, Sub 1023 (May 30, 2013) (2013 DEP Rate Order), which was affirmed by the Supreme Court in State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 444, 761 S.E.2d 640 (2014) (Cooper III)[6];

- 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); and

- 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.

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

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

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

> To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting an ROE, the Commission must still provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. State ex rel. Utilities Commission v. General Telephone Co. of the Southeast, 281 N.C. 318, 370, 189 S.E.2d 705, 757 (1972). As the Supreme Court

[6] 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.

> held in that case, these factors constitute "the test of a fair rate of return declared" in Bluefield and Hope. Id.

2013 DEP Rate Order, at 29.

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

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

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

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

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

* * *

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

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

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

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

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

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

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

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

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

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

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

Charles F. Phillips, Jr., The Regulation of Public Utilities, 3d ed. 1993, pp. 381-82. (notes omitted)

2013 DEP Rate Order, pp. 35-36.

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

The Supreme Court in Cooper V affirmed the 2013 DEC Rate Order, in which this framework was fully articulated. But to the framework we can add additional factors based upon the Supreme Court's decisions in Cooper III, Cooper IV, and Cooper V. Specifically, the Supreme Court held that nothing in Cooper I requires the Commission to "quantify" the influence of changing economic conditions upon customers (see, e.g., Cooper V, 367 N.C. at 745-46; Cooper IV, 367 N.C. at 650; Cooper III, 367 N.C. at 450), and, indeed, the Supreme Court reiterated that setting the rate of return on equity is a function of the Commission's subjective judgment: "Given th[e] subjectivity ordinarily inherent in the determination of a proper rate of return on common equity, there are inevitably pertinent factors which are properly taken into account but which cannot be quantified with the kind of specificity here demanded by [the appellant]." Cooper III, 367 N.C. at 450, quoting State ex rel. Utils. Comm'n v. Pub. Staff-North Carolina Utils. Comm'n, 323 NC 481, 490 (1988).

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

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

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

1. Evidence from expert witnesses on cost of equity capital

Company witness Hevert recommended in his direct testimony a rate of return on equity of 10.75%, which was slightly above the midpoint of his recommended range of 10.25% to 11.00%. Witness Hevert's direct testimony explained the importance of a utility being allowed to earn a rate of return on equity that is adequate to attract capital at reasonable terms, under varying market conditions, and that will enable the utility to provide safe, reliable electric service while maintaining its financial integrity. Witness Hevert explained that unlike the cost of debt, the cost of equity is not observable and must be estimated based on market data. Witness Hevert used the Constant Growth Discounted Cash Flow (DCF) model, the multi-stage DCF Gordon method, the multi-stage DCF Terminal Price/Earnings, the Capital Asset Pricing Model (CAPM), and the Bond Yield Risk Premium. He testified that his recommendation also takes into consideration factors such as DEP's risks associated with environmental regulations, flotation costs, and the increasing uncertainty in the capital markets. Witness Hevert also focused upon capital market conditions as they affect the Company's customers in North Carolina.

For his DCF calculation dividend yield, witness Hevert used the average daily closing prices for the 30-trading days, 90-trading days, and 180-trading days as of March 31, 2017. He then calculated the DCF results using each of the following growth terms:

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

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

EPS growth rate estimates reported by Value Line, Zacks, and First Call with the subject company's dividend yield for each proxy company and then calculated the average result for those estimates. His constant growth DCF results ranged from 8.07% to 9.82%.[7]

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 DEP at a competitive disadvantage, and (3) makes it difficult for DEP to compete for capital at reasonable terms.

DEP 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 5.50% based on the real GDP growth rate of 3.22% from 1929 through 2016 and an inflation rate of 2.21%. He testified that the GDP growth rate is calculated as the compound growth rate in companies. Witness Hevert testified that his Multi-Stage DCF analysis produces a range of results from 8.72% to 9.28%.

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 3.06% and the near-term projected 30-year Treasury yield of 3.52%. 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 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 9.15% to 11.49%.

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

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[7] Table 13 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."

approaches, some of which incorporate ex-ante, or forward-looking, estimates of the cost of equity, and others that consider historical, or ex-post, estimates. An alternative approach is to use actual authorized returns for electric utilities to estimate the equity risk premium.

Witness Hevert testified that he first defined the risk premium as the difference between the authorized rate of return on equity and the then-prevailing level of long-term 30-year Treasury yield. He then gathered data for 1,508 electric utility rate proceedings between January 1980 and March 31, 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 200 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 10.00% and 10.32%.

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

Public Staff witness Parcell performed three rate of return on equity analyses using the constant growth discounted cash flow (DCF), the capital asset pricing model (CAPM), and comparable earnings (CE).

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

- Years 2012-2016 (5-year average) earnings retention, or fundamental growth;

- Five-year average of historic growth in earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS);

- 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. Witness Parcell's analysis using these five dividend growth indicators materially differed from DEP witness Hevert's sole use of analysts' predictions of earnings per share 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 8.4%, and the Hevert proxy group of 18 companies, where using only the highest mean growth rate the cost of capital was 9.3%. He recommended a DCF rate of return on equity of 8.85% for DEP as the mid-point of the two highest mean growth rates.

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

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

Public Staff witness Parcell performed a CAPM analysis, which describes the relationship between a security's investment risk and its market rate of return. For his risk-free rate, he used the three-month average yield for 20-year Treasury bonds. For the beta, which indicates the security's variability of return relative to the return variability of the over-all capital market, he used the most recent Value Line beta for each company in his proxy group. He calculated the risk premium by comparing the annual returns on equity of the S&P 500 with the actual yields of the 20-year Treasury bonds, by comparing the total returns (i.e., dividends/interest plus gains/losses) for the S&P 500 group as well as long-term government bonds, using both the arithmetic and geometric means. These analyses revealed the average expected risk premium to be 5.8%. His CAPM results collectively indicated a rate of return on equity of 6.1% to 6.7% for the Parcell and Hevert proxy groups.

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

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

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

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

1. To maintain the credit of the enterprise and confidence in its financial integrity;

2. To permit the enterprise to attract required additional capital on reasonable terms; and

3. To provide the enterprise and its investors with an earnings opportunity commensurate with the returns available on investments in other enterprises having corresponding risks.

Witness Parcell further testified that the comparable earnings method normally examines the experienced and/or projected return on book common equity. The logic for examining returns on book equity follows from the use of original cost rate base regulation for public utilities, which uses a utility's book common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return, which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base rate of return methodology used to set utility rates. Witness Parcel applied the comparable earnings methodology by examining realized rate of returns on equity for the Hevert and Parcell groups of proxy companies, as well as unregulated companies, and evaluated investor acceptance of these returns by reference to the resulting market-to-book ratios. Witness Parcell used the experienced rates of return on equity of the two proxy groups of utilities for the years 2002–2008 (the most recent business cycle) and 2009-2016 (the current business cycle) and projected ROE's 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 9.4% to 11.0% have been adequate to produce market to book ratios of 141% 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 9.8% to 10.6% for the utility groups. These relate to market to book ratios of 176% or greater. He also noted that the rates of return on equity and market to book ratios of his proxy group, which all range over $20 billion in market value exceed those of witness Hevert's proxy group, which are not selected based upon size.

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

Witness Parcell testified in support of the 9.9% rate of return on equity in the Stipulation. Witness Parcell explained that the Stipulation allows an overall rate of return of 7.09% based on 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 Dominion North Carolina Power's (DNCP) rate case, Docket No. E-22, Sub 532 (DNCP 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 proposed Stipulation is "global," except to the "Coal Ash" and storm cost issues in this proceeding.

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 9.20% (approximate mid-point of his range of 8.85% to 9.50%), and a cost of debt of 4.05%. However, given the benefits associated with entering a settlement, it was his view that the cost of capital components of the Stipulation are a reasonable resolution of otherwise contentious issues.

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

With respect to the rate of return on equity component of the Stipulation, witness Parcell testified that DEP requested a rate of return on equity of 10.75%, which witness Parcell stated in his direct testimony was well above industry norms in recent years. He proposed a 9.2% rate of return on equity (i.e., approximate mid-point of a rate of return on equity range of 8.85% to 9.50%, which was derived from his DCF model results of 8.85% and his comparable earnings results of 9.50%). Public Staff witness Parcell testified that while he continues to believe his specific 9.2% 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 0.70% above his 9.2% recommendation and is 0.85% below DEP's 10.75% rate of return on equity request. As a result, the 9.9% rate of return on equity in the Stipulation is a "compromise" between DEP'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 DEP's last rate proceeding.

Witness Parcell testified that he had employed the comparable earnings method in virtually all of his cost of capital analyses going back to 1972. He testified the comparable earnings analysis is based on the opportunity cost principal and is consistent with and derived from the Bluefield and Hope decisions of the U.S. Supreme Court, which are recognized as the primary standards for the establishment of a fair rate of return for a regulated public utility. The comparable earnings method is also consistent with the concept of rate base regulation for utilities, which employs the book value of both rate base and the capital financing rate base. He testified that his comparable earnings analyses considers the recent historic and prospective rates of return on equity for the groups of proxy utilities companies utilized by himself and DEP 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 recent DNCP rate proceeding, Docket No. E-22, Sub 532, Order dated December 22, 2016, DNCP and the Public Staff agreed to a settlement 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). The Commission approved the cost of capital components of that proposed settlement. Witness Parcell testified that the equity ratio and rate of return on equity in the proposed Stipulation in the current DEP proceeding are consistent with those of the DNCP proceeding.

DEP 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. Witness Hevert testified that although the stipulated rate of return on equity is below the lower bound of his recommended range of 10.25%, he recognized the

Stipulation represents negotiations among DEP and the Public Staff regarding otherwise contested issues. He testified that the Company has determined that the terms of the Stipulation, in particular the stipulated rate of return on equity and equity ratio, would be viewed by the rating agencies as constructive and equitable, and that he understands and respects that determination.

Witness Hevert testified that although the stipulated rate of return on equity falls below his recommended range, the low end of which is 10.25%, it is within the range of the analytical results presented in his direct and rebuttal testimonies. He testified that capital market conditions continue to evolve and as a consequence, the models used to estimate the cost of equity produce a wide range of estimates. Witness Hevert testified that he recognizes the benefits associated with DEP'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 November 2017, the average authorized rate of return on equity for vertically-integrated electric utilities was 9.85%, only five basis points from the stipulated rate of return on equity. Of the 75 cases decided during that period, 31 included authorized returns of 9.90% or higher.

Witness Hevert testified that given DEP'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 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.[8]

[8] Source: Regulatory Research Associates, accessed November 20, 2017.

Within RRA's ranking system, North Carolina is rated "Average/1," which witness Hevert testified falls in the top one-third of the 53 regulatory commissions ranked by RRA. Witness Hevert testified that the stipulated rate of return on equity falls 13 to 14 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 37 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 DEP's cost of equity.

Witness Hevert further testified that since January 2014, there have been 65 cases reported by RRA for vertically-integrated electric utilities in which an overall rate of return was specified. Over those 65 cases, the median rate of return was 7.45%, 36 basis points above the 7.09% rate of return contained in the Stipulation. He testified that from a slightly different perspective, 50 of the 65 cases had overall rates of return greater than 7.09%. He testified that the low overall rate of return contained in the Stipulation is brought about by DEP's rather low cost of debt.

AGO witness Polich testified that capital costs for utilities have been declining, not increasing, since DEP's last rate case order dated May 30, 2013, where the Commission approved an rate of return on equity of 10.2%. He testified that market data indicates a substantially lower rate of return on equity is sufficient. He cited DEP's most recent long-term debt issuance, which had an interest rate of 3.608%, adding that his recommended specific rate of return on equity of 8.48% would provide an implied 488 basis point premium over the coupon rate in DEP's September 2017 first mortgage bonds. He performed a two-step DCF and CAPM to reach his rate of return on equity recommendations.

Witness Polich's two-step DCF utilized the weighted average of two-thirds for short-term analysts five-year forecasted growth rate and one-third for the long-term growth rate of projected long-term US economic growth rate in gross domestic product published by the Energy Information Administration (EIA), the Social Security Administration, and IHS Global Insights. The results of his two-step DCF were the mean of the ROEs for the proxy group of 8.25%, and the median rate of return on equity of 8.48%. He testified he used the same proxy group as witness Hevert.

Witness Polich testified that one of the reasons that his analysis is so different than witness Hevert's multi-stage DCF is because witness Hevert uses a long-term growth rate of 5.5%, which is significantly higher than the projected economic long-term growth in U.S. Gross Domestic Product (GDP) from multiple reliable resources. For example, the EIA projects GDP to only grow at 4.14% through 2050. The Congressional Budget Office (CBO) projects Nominal GDP to grow at 3.97% through 2047 and a real GDP growth of 1.93%. He testified that the appropriate long-term GDP growth rate should be 4.22%, which is 128 basis points less than witness Hevert's figure. Witness Polich testified that witness Hevert's reliance on the exaggerated five-year growth rate significantly inflates his growth estimate and rate of return on equity calculations and does not reasonably reflect the need to use a longer-term growth rate in the two-step DCF model. Witness Polich testified that it is not reasonable to expect the regulated proxy group utilities to experience very long-term average dividend growth rates of 5.5% when the overall U.S. economy is only expected to grow at 4.22% over the same term.

For witness Polich's CAPM risk-free rate, he used the last ten-year average yield on 30-year Treasury bonds of 3.15% and the average last twenty-year average yield of 4.32%. For the risk premium, witness Polich used the forward-looking market risk premium of 5.75% recommended by KPMG Advisory N.V., Equity Risk Premium – Research Summary, July 13, 2017, and the 6.16% average risk premium over the last ten years calculated by Dr. Aswarth Damordaran, Professor of Corporate Finance and Valuation at the Stern School of Business at New York University.

Witness Polich used the same proxy group for his CAPM as his two-step DCF. For the proxy group beta, he used the mean of 0.708 and median of 0.675. His CAPM rate of return on equity analysis results were low mean rate of return on equity of 7.22%, weighted median rate of return on equity of 7.56%, and high mean rate of return on equity of 8.68%.

CUCA witness O'Donnell testified that the most useful methodology to produce realistic rate of return on equity results relative to prevailing capital markets, when applied appropriately, is the DCF. To check the reasonableness of his DCF analysis and to gauge the proper rate of return on equity to recommend within the DCF range, he also performed a Comparable Earnings analysis and the CAPM. Witness O'Donnell utilized a proxy group similar to DEP witness Hevert's except witness O'Donnell eliminated Avista Corp due to the pending takeover and SCANA Corp due to the controversy regarding the termination of construction at the Summer Nuclear Plant.

Witness O'Donnell calculated his DCF dividend growth rate using the historical retention of earnings, the historical 10-year and 5-year compound annual earnings per share, dividends per share, and book value per share as reported by Value Line, the Value Line forecasted compound annual rate of change for earnings share, dividends per share, and book value per share, and the forecasted rate of change for earnings per share that industry analysts supplied to Charles Schwab and Company. Witness O'Donnell's DCF growth rate was 4.75% to 5.75%, and his calculated DCF range was 7.75% to 8.75%

CUCA witness O'Donnell in his comparable earnings analysis included the earned returns on equity for his proxy group and Duke Energy Corporation over the period 2015 through 2022, balancing historical and forecasted returns. The past and forecasted earned returns for the proxy group were 9.25% to 10.25%, and the past and forecasted earned returns for Duke Energy Corporation were 7.5% to 8.5%. His recommended rate of return on equity based upon his comparable earnings analysis was the range of 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 he used was his proxy group was 0.72 and the beta for Duke Energy Corporation was 0.60.

For his risk premium analysis, witness O'Donnell used the long-term geometric and arithmetic returns for both large company equities and fixed income Long-Term Government Bonds with the resulting risk premium ranging from 4.60% to 6.20%. He also evaluated the predicted total market returns by a group of market experts, which ranged from 4.5% to 8%. He concluded that his equity risk premium was in the range of 4% to 6% and his CAPM resulted in an ROE range of 4.6% to 7.5%.

Commercial Group witnesses Chriss and Rosa testified that the average of 111 reported electric utility rate case rates of return on equity authorized by commissions to investor-owned utilities in 2014, 2015, 2016 and year-to-date 2017 was 9.65%. 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 2014 through present is 9.79%. They further testified that there is a continuing declining trend in authorized rates of return on equity for vertically integrated utilities over this time period. The average rate of return on equity authorized for vertically integrated utilities in 2014 was 9.92%; in 2015, 9.75%; in 2016, 9.77%; and so far in 2017, 9.70%.

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. Commercial Group provided the information in its testimony to illustrate a national customer perspective on industry trends in authorized rates of return on equity. Its 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 witness Phillips did not perform cost of capital analyses. He testified that DEP's requested rate of return on equity of 10.75% is excessive and should be rejected. He stated that DEP's current authorized rate of return on equity is 10.2%, which was authorized in the Commission's 2013 DEP Rate Order issued on May 30, 2013. Witness Phillips testified that costs of capital have declined since DEP's last rate case. Every quarter, Regulatory Research Associates, 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 June 30, 2017, shows that the national average authorized rate of return on equity for electric utilities in the first six months of this year is 9.61%, nearly 60 basis points below DEP's currently authorized rate of return on equity. Witness Phillips concluded that DEP's current approved rate of return on equity, and definitely its requested rate of return on equity, are significantly above the current market cost of equity. He recommended that the Commission authorize a rate of return on equity that does not exceed the national average of 9.61%.

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 DEP Sub 1023 Rate Case. In both of those cases rate of return on equity expert testimony from CUCA witness O'Donnell provided an alternate rate of return on equity analysis that pegged the utility's cost of capital at an amount lower than the settled rate of return on equity. The Supreme Court in Cooper I faulted the Commission for not making explicit its evaluation of this testimony, and, thus, the Commission in the 2013 DEP Rate Order made an express evaluation of witness O'Donnell's testimony in accordance with the Cooper I decision.

The Commission determines the appropriate rate of return on equity based upon the evidence and particular circumstances of each case. However, the Commission believes that the rate of return on equity trends and decisions by other regulatory authorities deserve some weight, as (1) they provide a check or additional perspective on the case-specific circumstances, and (2) the Company must compete with other regulated utilities in the capital markets, meaning that a rate of return on equity significantly lower than that approved for other utilities of comparable risk would undermine the Company's ability to raise necessary capital, while a rate of return on equity significantly higher than other utilities of comparable risk would result in customers paying more than necessary. In this connection, the analysis performed by Commercial Group witnesses Chriss and Rosa, as modified by witness Hevert, is instructive. Witnesses Chriss and Rosa noted that according to data from SNL Financial for 2014 through the 2017 hearing date, authorized rates of return on equity across the country for vertically-integrated electric utilities have been in the range of 9.20% to 10.55%. Witnesses Chriss and Rosa calculated the mean authorized rate of return on equity for vertically-integrated utilities like DEP to be 9.79%. Witness Hevert, in commenting upon and evaluating their testimony in his Rebuttal Testimony, refined their analysis and presented his findings in Exhibit RBH-R21 to add in jurisdictional rankings. Doing so results in a rate of return on equity range from 9.70% to 10.55%, with a median of 10.14%. (Tr. Vol. 8, pp. 158-59.) The Settlement 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 9.85%, only five basis points from the Settlement 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 10.03%, 13 basis points above the 9.90% Settlement ROE [rate of return on equity]." (Id. at 330.) 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 DEP's required rate of return on equity at that level, in the context of the Stipulation as a whole, and witness Hevert was subjected to extensive cross-examination. Thus, the Commission finds and concludes that the Stipulation, along with the expert testimony of witnesses Hevert (risk premium analysis), O'Donnell (comparable earnings), and Parcell (comparable earnings), are credible and substantial evidence of the appropriate rate of return on equity and are entitled to substantial weight in the Commission's determination of this issue.

3. Evidence of Impact of Changing Economic Conditions on Customers

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

a. Discussion and Conclusions Regarding Evidence Introduced During the Evidentiary Hearing

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

DEP 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 February 2017, the unemployment rate had fallen to one-half of those peak levels: 4.70% nationally, and 5.10% in North Carolina. Since DEP's last rate filing in 2012, the unemployment rate in North Carolina has fallen from 9.00% to 5.10%.

Witness Hevert testified that with respect to GDP there also has been a relatively strong correlation between North Carolina and the national economy (approximately 67.00%). 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 86.00% 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 DEP. At the unemployment peak, which occurred in late 2009 into early 2010, the unemployment rate in those counties reached 12.65% (1.65 percentage points higher than the State-wide average); by February 2017 it had fallen to approximately 5.60% (0.60 percentage points higher than the State-wide average). Since DEP's last rate filing in 2012, these counties' unemployment rates have fallen by over 4.00 percentage points.

Witness Hevert testified that it was his opinion that, based on the indicators discussed above, North Carolina and the counties contained within DEP's service area continue to steadily emerge from the economic downturn that prevailed during DEP'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 DEP.

Witness Parcell testified that DEP provides service in 51 counties, and that the 18 North Carolina Department of Commerce classified Tier 1 counties had an August 2017 not-seasonally-adjusted combined unemployment rate of 5.8%, with a combined total of 17,317 persons unemployed, and a combined total labor force of 298,459 persons. The 20 Tier 2 counties had an August 2017 not-seasonally-adjusted combined unemployment rate of 5.6%, with a combined total of 43,789 persons unemployed and a combined total labor force of 781,690 persons. The 13 Tier 3 counties had an August 2017 not-seasonally-adjusted combined unemployment rate of 4.0%, with a combined total of 56,743 persons unemployed, each with a combined total labor force of 1.431 million persons. The August 2017 not-seasonally-adjusted North Carolina unemployment rate was 4.5%. He testified that all 51 counties experienced a drop in their not-seasonally-adjusted unemployment rates between August 2016 and August 2017, averaging a 0.9% decrease compared to the statewide decrease of 0.8%. Witness Parcell further testified the North Carolina Department of Commerce in its September 2017 NC Today stated that North Carolina industry employment had an increase of 70,500 over the year, an increase in real taxable retail sales of $643.9 million over the year, an increase in residential building permits of 3.4% over the year, and an increase in job postings of 8.3% 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 DEP customers. He concluded by stating that the Commission's duty to set rates as low as reasonably possible consistent with constitutional requirements without jeopardizing adequate and reliable service is the same regardless of the customer's ability to pay.

b. Evidence Introduced During Public Hearings and Further Conclusions

The Commission's review also includes consideration of the evidence presented during the public hearings by public witnesses, almost all of whom presently are customers of DEP. The hearings provided over 140 witnesses the opportunity to be heard regarding their respective positions on DEP's application to increase rates. The Commission held five evening hearings throughout DEP's North Carolina service territory to receive public testimony. The testimony presented at the hearings illustrates in detail the difficult economic conditions facing numerous North Carolina citizens. A representative sample of the public witness testimony received on the topic is summarized below.

At the public hearing in Rockingham, witnesses Wood, Hall, Bostic, McCall, Zucchino, Merrell, and Tucker testified that those living on a fixed or limited income cannot afford, and would be disparately impacted by, DEP's proposed rate increase. Some of the same witnesses testified that any increase to the basic customer charge would be particularly problematic because it would discourage energy conservation and preclude customers from reducing electric usage as a means of offsetting increased rates.

At the public hearing in Raleigh, witnesses Finch, Mallam, Richmond, Girolami, Toman, Rodriguez, Bearden, Cygan, Goodson, Seabolt, Adams, Malone, Von Schonfeld, Garrity, Karasik, and Henry testified that those with a fixed or limited income cannot afford, and would be disparately affected by, DEP's proposed rate increase. Some of the same witnesses testified that any increase to the basic customer charge would be particularly problematic because it would discourage energy conservation, preclude customers from reducing electric usage as a means of offsetting increased rates, and reduce customers' ability to invest in their own energy efficiency and renewable energy measures. Witnesses Mallam, Rodriguez, Seabolt, and Garrity testified that costs related to power plants never used or useful to the consuming public or abandoned prior to completion reflect poor management decisions by DEP, and, therefore, should be excluded from recovery through the rate base. Witness Tart testified that initiatives such as community solar could reduce costs of energy generation and, thus, reduce the need for DEP to apply for future rate increases.

At the public hearing in Asheville, witnesses Whalen, Maddox, Biziewski, Rouse, and McGlinn testified that DEP's proposed increase to the basic customer charge should be denied because it would discourage energy conservation, preclude customers from reducing electric usage as a means of offsetting the increased rates, and benefit, at the expense of low-income and renewable energy residential customers, industrial or business customers who consume the most energy. Witnesses Whalen, Culver, Williams, Biziewski, Rouse, Boatright on behalf of Cruz-Segarra, Wilds, McGlinn, Kohnle, Huttman on behalf of Williams, Brill, V. Williams, Mac Arthur, and Rountree testified that those with a fixed or limited income cannot afford, and would be disparately affected by, DEP's proposed rate increase. Witnesses Hollister, Biziewski, Blow, Laubach, Rouse, Brame, Hale, Boatright, Carson, Carter, Holt, Smith, Kohnle, Friedrich, Whitmire, Brill, Craig, Anderson, Fireman, White, Norris, Houghton, Livsey, Mac Arthur, and Stangler testified that DEP is spending too much money on gas-fired plants, and instead should invest more on energy efficiency and renewable energy initiatives. Witness Huttman on behalf of Williams testified that DEP's requested rate increase would be bad for small businesses and local economies.

At the public hearing in Snow Hill, witnesses Herring, Harroway, Taylor, Schachter, Hinnant, Dantonio, Gurley, Poland, Gallimore, Wright, Battle, Liles, and Mullens testified that those with a fixed or limited income cannot afford, and would be disparately affected by DEP's proposed rate increase. Witnesses Taylor, Shachter, and Battle testified that DEP's proposed increase to the basic customer charge should be denied because it would discourage energy conservation, preclude customers from reducing electric usage as a means of offsetting the increased rates, and disproportionately affect the customers who use the least amount of energy. Witnesses Winstead, Wood, and Emerson testified that DEP's application for a rate increase is unjustified because current infrastructure can support the mostly flat demand for energy for years to come, non-public utility rates have decreased, and the price of fuel to generate electricity has decreased. Witness Bain testified that costs related to power plants never used or useful to the consuming public or abandoned prior to completion reflect DEP's poor management practices, and, therefore, should be excluded from recovery through the rate base.

At the public hearing in Wilmington, witnesses Bondurant and Gillman-Bryan testified that, while a partial rate increase would be acceptable, the full amount requested by DEP is excessive. Witnesses Bondurant, Maxwell, Stutts, Herbert-Harkin, Wooten, Lafollette-Black, Nofziger, Leonard, Blackburn, McKay, Porter, Bradley, Buckles, Murray, Murphy, Sheppard, Greiner, and Richardson testified that those with a fixed or limited income cannot afford, and would be disparately affected by, DEP's proposed rate increase. Witneses Gillman-Bryan, Szmant, Feris-Harkin, Porter, Richardson, Maynard, Bradley, and Thackston testified that DEP's stock consistently has performed well and its shareholders consistently have profited, and, therefore, DEP should seek from shareholders and investors whatever funds are needed for DEP to operate.

The Commission accepts as credible, probative, and entitled to substantial weight the testimony of the public witnesses.

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

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

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

Economic conditions existing during the test year, at the time of the public hearings, and at the date of this Commission Order affect not only the ability of DEP's consumers to pay electric rates, but also the ability of DEP to earn the authorized rate of return during the period rates will be in effect. Pursuant to G.S. 62-133, rates in North Carolina are set based on a modified historic test period.[9] A component of cost of service as important as return on investment is test year revenues.[10] 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.

DEP 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 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

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

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

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 DEP'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 DEP filed rate schedules that would have produced annual revenues of $3,560,767,000. This is the amount ratepayers would pay. These revenues, pursuant to the Application, would have produced $625,570,000 in return on investment. Of this amount $463,224,000 was the return that would have been paid to equity investors, the "return on equity." Pursuant to the Application the "rate of return on equity" financed portion of the investment (as distinguished from the "return on equity") would have been 10.75%.

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

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

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

Based on the changing economic conditions and their effects on DEP's customers, the Commission recognizes the financial difficulty that the increase in DEP's rates will create for some of DEP'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 DEP's customers in reaching its decision regarding DEP'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 DEP's customers against the benefits that those customers derive from the Company's ability to provide safe, adequate and reliable electric service. Safe, adequate and reliable electric service is essential to the well-being of the people, businesses, institutions, and economy of North Carolina.

The Commission finds and concludes that these investments by the Company provide significant benefits to all of DEP's customers. The Commission concludes that the return on equity approved by the Commission in this proceeding appropriately balances the benefits received by DEP's customers from DEP'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 DEP's customers will experience in paying DEP's increased rates.

Finally, the Commission gives significant weight to the Stipulation and the benefits that it provides to DEP'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 DEP originally requested a retail revenue increase of $477 million, or a 14.9% 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 DEP reached a Stipulation that resulted in reducing the retail revenue increase sought by the Company by approximately $73 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 DEP's Application and pre-filed testimony, it is apparent that the Stipulation ties the 9.9% rate of return on equity to substantial concessions the Company made.

Summary and Conclusions on the Rate of Return on Equity

The Commission has carefully evaluated the return on equity testimonies of DEP witness Hevert, Public Staff witness Parcell, AGO witness Polich, CUCA witness O'Donnell, Commercial Group witnesses Chriss and Rosa, and CIGFUR witness Phillips. The Commission finds that the comparable earning analysis testimony of Public Staff witness Parcell, the risk premium analysis testimony of DEP witness Parcell, 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 earning recommended rate of return on equity range was 9.0% to 10.0%. The Commission approved rate of return on equity of 9.9% is in the upper portion of his range. As testified by witness Parcell, the comparable earnings analysis is based on the opportunity cost principal and is consistent with and derived from the Bluefield and Hope decisions of the U.S. Supreme Court, which are recognized as the primary standards for the establishment of a fair rate of return for a regulated public utility. The comparable earnings method is also consistent with the concept of rate base regulation for utilities, which employs the book value of both rate base and the capital financing rate base. Witness Parcell testified that his comparable earnings analyses considers the recent historic and prospective rates of return on equity for the groups of proxy utilities companies utilized by himself and DEP 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.

DEP 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 DEP 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 DEP.

DEP 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 10 basis points below witness Hevert's risk premium's implied rate of return on equity range of 10.0% to 10.32%.

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

In its post-hearing Brief, CUCA contends that DEP's testimony directly contradicts the testimony of its rate of return witness Hevert. CUCA states that witness Hevert's cost of equity recommendation is significantly higher than what DEP contends is its "market return" for its decommissioning expenses and its pension costs. According to CUCA, if DEP's "market returns" matched Hevert's 10.75% recommendation, then no additional rate increase would be needed for these costs, and the Commission should not reward DEP for inconsistent testimony.

In its post-hearing brief, the AGO contends that establishing an 8.48% rate of return on equity is supported by stock market data showing what investors require under current economic conditions, fairly balances the interests of investors and consumers, reduces the revenue requirement by another $96.1 million per year, and is supported by the results of the DCF analyses performed by the expert witnesses. (Tr., Vol. 13, p. 126.) In addition, the AGO submits that DEP has not met its burden of proof that the 9.9% rate of return on equity proposed in the Stipulation fixes a reasonable return given the low cost of equity capital in current markets.

The AGO summarizes the DCF analyses of witnesses Polich, Hevert, O'Donnell and Parcell. The AGO contends that witness Hevert's analyses are generally flawed by the use of methods and inputs that are "systematically biased upward in a manner that significantly inflates his cost of equity conclusions" (Parcell Tr. Vol. 14, p. 79), and submits that the reason that his DCF results are so much higher than those produced by the other witnesses is that he used much higher long-term growth factors in his multi-stage DCF models. (Tr. Vol. 13, p. 95.) The AGO states that the utilities commission in Missouri came to a similar conclusion that witness Hevert's analyses overstated growth factors in 2015 when it examined similar analyses that he performed for Ameren Missouri (Tr. Vol. 8, pp. 386-87), finding that his multi-stage DCF analysis was based on a nominal long-term GDP growth rate outlook that was overly optimistic, and that by adjusting his DCF analysis to reflect the level of consensus economists' forward-looking real GDP growth outlooks, his DCF study would have produced an 8.8% rate of return on equity estimate instead of a 10.02% rate of return on equity. (Tr. Vol. 8, pp. 386-87.) Further, the AGO states that the Missouri commission also found that witness Hevert's CAPM analysis used an unreasonably high estimate of projected market returns. (Tr. Vol. 8, p. 387.)

According to the AGO, witness Hevert gave little weight to the market data in his DCF analysis because he contends that it would reduce the rate of return on equity in this case too much from the rate of return on equity approved in DEP's last rate case. (Tr. Vol. 8, p. 171.) However, the AGO contends that the fact that the rate of return on equity would drop considerably is not an appropriate consideration and relies incorrectly on the assumption that the rate of return on equity in DEP's existing rates is a starting point for measuring how much the cost of capital has changed.

The AGO states that witnesses Polich, Parcell, and O'Donnell performed rate of return on equity estimates using the CAPM and that their CAPM results are significantly lower than the results of the DCF studies they performed. On the other hand, according to the AGO witness Hevert's CAPM produced even higher results at the top of his CAPM range. The AGO witness states that the main factor that caused witness Hevert's high CAPM results is his over-estimate of the projected returns associated with equity capital as compared to risk-free investments (i.e., the risk premium), and that he relies on problematic DCF analyses to estimate projected equity returns. (Tr. Vo. 14, pp. 89-90.) The AGO states that the flawed effect of his over-estimated projection of the risk premium was also observed by the Missouri commission in its 2015 Order. (Tr. Vol. 8, p. 387.)

The AGO notes that another model used by witness Hevert is the Risk Bond Yield Premium, using data about the rates of return on equity authorized by regulators in other rate proceedings to estimate a rate of return on equity. The AGO states that the authorized rates of return reflect policies and underlying data estimates of market conditions that are not provided in the record in this case, and contends that it is not appropriate for the Commission to determine DEP's rate of return on equity based on such evidence, citing Cooper II, 367 N.C. at 443, 758 S.E.2d at 643; State ex rel. Utilities Comm'n v. Public Staff, 331 N.C. 215, 225, 415 S.E.2d 354, 361 (1992).

Moreover, the AGO states that witness Parcell also used a Comparable Earnings (CE) study that compares the actual return expected on the original cost book value of enterprises with similar risk, and evaluates investor acceptance of the returns as indicated by the resulting market-to-book ratios. (Tr. Vol. 14, p. 74.) From his analysis he posits that a 9.5% CE result (the midpoint of his range) is well above the actual earned rate of return on equity for the regulated companies, (Id.), and is more than sufficient for the company to attract new equity capital without dilution. (Tr. Vol. 14, p. 75.)

The AGO maintains that a thoughtful review of the rate of return on equity is important because even a seemingly small change to DEP's authorized rate of return on equity makes a difference of millions of dollars in DEP's revenue requirement. Further, the AGO states that North Carolina law requires the Commission to fix a rate of return that is fair to the utility's investors and its customers, citing G.S. 62-133(a), 62-133(b)(4); Cooper I, 366 N.C. at 495, 739 S.E.2d at 548; Bluefield, and Hope. The AGO further notes that the burden of proof in this case is upon DEP to show that its proposed rates are just and reasonable, pursuant to G.S. 62-75 and 62-134(a), and that the Commission must conduct an independent analysis of the evidence and reach its own conclusion when it fixes the rate of return on equity. Cooper I, 366 N.C. at 494, 739 S.E.2d at 547.

Further, the AGO states that the Commission may consider the multiple items addressed in the Stipulation, but that it is beyond the Commission's authority to fix an excessive rate of return on equity negotiated in exchange for other factors addressed in the Stipulation. According to the AGO, North Carolina's ratemaking statute requires the Commission to "fix" the rate of return, taking into account specific considerations. See G.S. 62-133(b)(4); Thornburg II, 325 N.C. at 490, 385 S.E.2d at 466 ("Section 62-133 provides a step-by-step procedure for the Commission to follow in fixing these rates.").

Finally, the AGO posits that although North Carolina is doing well as a state in terms of growth, North Carolina households have less ability on average to absorb increases in the cost of living – such as utility rate hikes – because per capita income is considerably lower than in other states, while the cost of living is not. (Tr. Vol. 13, p. 115.) The AGO notes that North Carolina has recently enjoyed a stronger GDP growth rate than the national average and that the cost of living index for North Carolina is slightly lower (1.1%) than the national average, but that per capita income is well below the national average (13.8% lower) and income has grown at a slower pace than the nation as a whole. (Tr. Vol. 13, p. 113.) In addition, the AGO summarizes the testimony of public witnesses regarding the impact of the proposed rate increase and their concerns.

Commercial Group, in its post-hearing Brief, notes that the Commission approved a rate of return on equity of 10.2% for DEP in its last rate case in 2013 and that since then average returns for electric utilities across the country have dropped to 9.63% as of 2017. Commercial Group opines that although the Stipulation rate of return on equity would result in DEP receiving an above-average rate of return on equity, the reduction in the proposed rate of return on equity from 10.2% to 9.9% is a reasonable step in the right direction, particularly when combined with a slight decrease in the equity ratio and cost of debt that are provided in the Stipulation. Nevertheless, Commercial Group submits that based on the rate of return on equity testimony of witnesses Chriss and Rosa the Stipulation rate of return on equity of 9.90% should serve as an upper limit on rate of return on equity with respect to a gradual approach of moving DEP's rate of return on equity more in line with that of utilities across the country. In conclusion, Commercial Group recommends adoption of the Stipulation rate of return on equity of 9.90% and the overall weighted cost of capital of 7.09%.

The Commission has carefully evaluated the DCF analysis recommendations of witnesses Parcell, Hevert, Polich, and O'Donnell, and the Commission gives minimal 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 2014 through the hearing in 2017 was 9.2%. Witness Parcell's specific DCF result was 8.85%, witness Polich's was 8.48%, and the mid-point of witness O'Donnell's was 8.25%. The average of Hevert's constant growth DCF means was 8.92%, and the mid-point of the range of witness Hevert's Multi-Stage DCF analysis was 9.0%. The Commission considers all of these DCF results to be outliers, being well below the lowest vertically-integrated rate of return on equity of 9.2%. The Commission determines that all of these DCF analyses in the current market produce unrealistic low results.

The Commission gives no weight to any of the witnesses' CAPM analyses. The analyses of witness Parcell with a mid-point of 6.4% 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 6.05%, which is an outlier well below the 9.2% previously discussed. Witness Polich's CAPM weighted median rate of return on equity of 7.56% is also an outlier and unrealistically low. DEP Witness Hevert's CAPM range of 9.15% to 11.49% is also an outlier and upwardly biased due to his use of the near-term projected 30-year Treasury interest rate of 3.52%, which witness Parcell testified greatly exceeds the current level of long-term Treasury of about 2.8%. Witness Hevert's risk premium component of this CAPM uses a constant growth DCF for the S&P 500 companies using analysts projected earnings per share forecasts as the growth component. Witness Hevert's DCF dividend growth, component based solely on analysts' earnings per share 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 2014, 2015, 2016, and year-to-date 2017 listed in Commercial Group Exhibit CR-3. The Commission gives weight to this testimony only as a check on the Commission's approved 9.9% rate of return on equity and to evaluate outlier rate of return on equity recommendations. CIGFUR witness Phillips' testimony focused on the RRA report Major Rate Case Decisions. The 9.61% average authorized rate of return on equity for electric utilities included both vertically-integrated electric utilities and distribution-only electric utilities. Since DEP 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 noted above, recently authorized rates of return on equity for vertically-integrated electric utilities since 2014 average 9.85%, and in jurisdictions with constructive regulatory environments average 10.03%, and serve as a better check.

The 9.9% rate of return on equity approved in this proceeding for DEP is also consistent with the 9.9% rate of return on equity the Commission approved for DNCP in the Order dated December 22, 2016, in Docket No. E-22, Sub 532.

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 DEP 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

DEP originally proposed using a capital structure of 53% members' equity and 47% long-term debt. (Tr. Vol. 8, p. 24.) The Stipulation provides for a capital structure of 52% equity and 48% long-term debt. For the reasons set forth herein, the Commission finds that a 52/48 capital structure as set out in the Stipulation is just and reasonable.

Witness De May testified that the Company's "specific debt/equity ratio will vary over time, depending on the timing and size of debt issuances, seasonality of earnings, and dividend payments to the parent company." (Tr. Vol. 8, p. 29.) As of the end of the test year, the actual regulatory capital structure[11] was 52.5% equity and 47.5% debt (Id. at 44), and the 13-month average equity ratio was 53.5%. (Id.) This average equity ratio was maintained by DEP through June 2017. (Id.) The 52/48 capital structure agreed to in the Stipulation represents a compromise between the Company's 53/47 position and the Public Staff's recommendation of a 50/50 capital structure. Both witness Parcell, for the Public Staff, and witness De May, for the Company, supported the agreed upon 52/48 ratio. (Tr. Vol. 14, pp. 109-10 (Parcell) (52/48 ratio reflects a reasonable compromise, and also "incorporate[s] a reduction" from the Company's currently authorized 53/47 ratio); Tr. Vol. 8, p. 54 (De May).) De May indicates that the "stipulated capital structure is reasonable when viewed in the context of the overall Partial Settlement," and it would be positively viewed by the ratings agencies that set the Company's credit ratings. (Id.) Witness Hevert's settlement testimony also supported the stipulated 52/48 capital structure. (Id. at 330-31.)

CUCA witness O'Donnell and AGO witness Polich recommend that the Commission reject the Company's capital structure proposal and instead advocate a 50/50 hypothetical structure. Witness Polich provided no analysis to support his recommendation. He merely asserts, without any cited evidence, that "[i]n the utility industry, it is common to target the percentage of debt and equity at 50% each." (Tr. Vol. 13, p. 117.) As witnesses De May and Hevert demonstrate in their rebuttal testimony, this assertion is simply wrong. (Tr. Vol. 8, p. 41 (De May); id. at 242; Ex. RBH-R19 (Hevert).) Further, witness Polich states that the reason the Commission should move to an artificial 50/50 capital structure is "to lower rates." (Tr. Vol. 13, p. 118.) But as witness De May indicates, "[s]etting an artificial capital structure simply for the purpose of lowering rates presents great risk." (Tr. Vol. 8, p. 48.) In the 2013 DEC Rate Case, for example, the AGO argued that a 50/50 capital structure should be implemented for utility, but, like witness Polich in this case, provided "no probative or persuasive evidence suggesting that a 50/50 capital structure is in fact appropriate." (2013 DEC Rate Order, at 52.) The Commission rejected the AGO's argument because that argument did not "recognize the

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

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 DEP'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. 8, p. 47.)[12] Second, as the Commission has already held in this case in connection with its ROE 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 DEP Rate Order, at 37 (emphasis added).

Unlike witness Polich, witness O'Donnell provided an analysis purporting to support his 50/50 capital structure recommendation, but that analysis is seriously flawed. The principal rationale for witness O'Donnell's 50/50 recommendation is his comparison of capital structures of publicly-traded holding companies, not operating utility companies. (Tr. Vol. 15, pp. 196-97.) This Commission has previously commented on and rejected the use of parent company structures as opposed to operating company structures in determining the operating utility's appropriate equity/debt ratio. See Order Granting General Rate Increase and Approving Amended Stipulation, Docket No. E-7, Sub 909 (December 7, 2009) (2009 DEC Rate Order), at 27-28. Parent and operating companies 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. 8, p. 239.) In addition, witness Hevert notes, 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

[12] Witness De May indicated in his Settlement Testimony that the slight move away from the 53/27 proposed capital structure represented by the Stipulation would likely still be viewed as credit supportive by the ratings agencies. (Tr. Vol. 8, p. 54.) 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.

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. (Id.) Here all three criteria are met. DEP does issue its own debt and is rated separately from its parent company, and the evidence presented by witnesses De May and Hevert shows that its capital structure is generally consistent with that of other operating companies, especially vertically-integrated companies. (Id. at 41 (De May); Id. at 316 (Hevert).)

Witness Hevert testified that he believes the stipulated capital structure is reasonable, as the stipulated equity ratio is nearly equal to the 2017 RRA reported median authorized equity ratio (i.e., 51.90%) of vertically-integrated electric utilities for commissions in regulatory environments considered above average, and it is within the range of equity ratios authorized in those jurisdictions (40.25% to 58.96%). He testified that the stipulated equity ratio falls within the range of authorized equity ratios, and within ten basis points of the median, for above average jurisdictions. In his view, that finding provides additional support for its acceptance.

In its post-hearing Brief, the AGO states that over $100 million is added to DEP's annual revenue requirement unnecessarily under the rate of return on equity and capital structure factors agreed to in the Stipulation. The AGO submits that DEP has not met its burden of proof that the 52% equity/48% debt capital structure is required, or that a 50/50 equity/debt structure uses too much debt leverage. The AGO contends that establishing a 50% equity/50% debt capital structure is sufficiently conservative, fairly balances the interests of investors and consumers, and reduces the revenue requirement by over $10.5 million per year. Further, the AGO states that DEP has not shown that a 50/50 equity/debt capital structure is overly-leveraged for a utility, or that it would harm DEP's financial integrity or its ability to access capital markets as needed. The AGO contends that DEP's high credit rating indicates that a 50/50 capital structure can be adopted without compromising DEP's financial integrity and that the proposed 52% equity capital structure exceeds the actual test period capital structure, which was 51.2% equity (including the current maturities of debt and refinancing). (Tr. Vol. 8, p. 48.) Moreover, according to the AGO and a table that it presents, a 50/50 capital structure is similar to the capital structures used for comparable investments and exceeds the average equity ratio for the other electric utilities that were used in the proxy groups to show comparable investments. In addition, the AGO lists the average equity ratios authorized in regulatory commission determinations over the past five years and states that the proposed 52% equity capital component exceeds those averages. The AGO also notes that the proposed 50/50 ratio maintains considerably more equity in the ratio than is presently maintained by DEP's parent company, Duke Energy, and that Duke Energy previously maintained an equity ratio comparable to the subsidiary, but more recently its equity ratio has declined to 46.1% at the end of 2016 and 45.3% as of June 3, 2017. (Tr. Vol. 8, pp. 394-96; Tr. Vol. 14, p 48.)

In conclusion, the AGO states that taking these factors into consideration, a 50% equity ratio is sufficiently conservative for DEP to access credit markets at reasonable rates and is fairer to consumers because it reduces the revenue requirement substantially.

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

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

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

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

Cost of Debt

In its Application, the Company proposed a long-term debt cost of 4.17%. The Stipulation provides for a 4.05% cost of debt. The Commission finds for the reasons set forth herein that a 4.05% cost of debt is just and reasonable.

In her pre-filed direct testimony, Company witness Bateman testified that the Company's revenue requirement was determined using an embedded cost of long-term debt of 4.17%.

Public Staff witness Parcell in his direct testimony supported the embedded cost of debt of 4.05%, as included in the Stipulation. He testified that the recent decline in interest rates was considered in the Stipulation, including the long-term debt First Mortgage Bonds Taxable issued by DEP on September 8, 2017. Witness Parcell explained that the 4.05% debt rate is low by historic standards and lower than the embedded cost of debt as of the end of the test year. The Stipulation's 4.05% debt cost gives customers the benefit of reductions in DEP's lower cost of debt after the end of the test year.

No intervenor offered any evidence for a debt cost below 4.05%. The Commission, therefore, finds and concludes that the use of a debt cost of 4.05% 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 of fact and conclusions is contained in the Stipulation, the verified Application and Form E-1 of DEP, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

In her direct testimony, Company witness McGee provides support for the fuel component of proposed base rates for all customer classes and the fuel pro forma adjustments to the test year operating expenses contained in Bateman Exhibit 1. (Tr. Vol. 10, p. 101.) Witness McGee testified that the Company proposes to use the following base fuel factors by customer class (excluding gross receipts tax and regulatory fees):

- Residential 1.933 cents per kWh
- Small General Service 2.088 cents per kWh
- Medium General Service 2.431 cents per kWh
- Large General Service 2.253 cents per kWh
- Lighting 0.596 cents per kWh

(Id.) She explained that these proposed factors are equal to the total prospective fuel and fuel-related cost factors approved in Docket No. E-2, Sub 1107 and implemented December 1, 2016. (Id.) These factors represent the fuel-related amounts that DEP was collecting from its North Carolina retail customers through its approved rates at the time of preparation of the Company's Application in this docket. (Id.) Witness McGee stated that DEP's intent in using the fuel-related factors that were in effect at the time that the Company's Application was prepared as a component of its proposed new rates was to make it clear that the Company is requesting a rate increase that relates to non-fuel revenues only. (Id.) She clarified that there will be no change in customers' bills as a result of including these fuel cost factors in the proposed base rates. (Id. at 103.) The Company will continue to bill customers the fuel rates authorized by the Commission in its annual fuel proceedings. (Id.)

As shown on McGee Exhibit 1, the Company's North Carolina retail adjusted fuel and fuel-related costs expense for the test period was $807,561,119. (Id. at 102.) According to witness McGee, this amount was calculated using the base fuel cost factors identified above and North Carolina retail test period actual sales by customer class as adjusted for weather and customer growth. (Id.) She testified that these amounts were used in the Company's pro forma adjustment calculations and are incorporated in the operating expenses shown on Bateman Exhibit 1. (Id.)

DoD/FEA witness Mancinelli is the only intervenor witness to challenge witness McGee's testimony on issues other than beneficial reuse of coal ash. Witness Mancinelli contended that the Company has distorted cost of service results by class as a result of improperly aligning allocated fuel expense with fuel clause revenues from base fuel factors approved in Docket No. E-2, Sub 1107. (Tr. Vol. 17, pp. 147-51.) Witness Mancinelli maintains that class rate adjustments should be based on cost of service results without added subsidizations associated with base fuel factors. (Id.)

In her rebuttal testimony, Company witness McGee testified that the Company does not agree with witness Mancinelli's position that the Company's reported net income and return on rate base on a customer basis are skewed due to subsidies associated with fuel revenues. (Tr. Vol. 10, p. 155.) The Company assigned fuel revenue to each customer class based on the fuel rates approved in the annual fuel adjustment proceeding, Docket No. E-2, Sub 1107. (Id.) She explained that to negate the fuel impact in this case, the pro forma adjustment to fuel expense was based on the same customer class allocation methodology approved in that docket. (Id. at pp. 155-56.) Witness McGee demonstrated that as a result, the net income impact for each rate class is zero. (Id. at 156.) She added that if witness Mancinelli disagrees with the use of the equal percentage methodology approved in the Company's annual fuel proceeding, the more appropriate forum to raise this issue is in the annual fuel adjustment docket. (Id.)

Section IV.C. of the Stipulation sets forth the Stipulating Parties' agreed upon total of the approved base fuel and fuel related cost factors, by customer class, as set forth in the following table (amounts are ¢/kWh excluding, regulatory fee):

	Res	SGS	MGS	LGS	Lighting
Total Base Fuel (matches approved fuel rate effective December 1, 2016, in Sub 1107)	1.993	2.088	2.431	2.253	0.596

These values are consistent with those recommended by witness McGee and approved in Docket No. E-2, Sub 1107. The Stipulation also notes that billed fuel rates shall be adjusted to reflect changes to fuel rates approved by the Commission in Docket No. E-2, Sub 1146, effective December 1, 2017.

Aside from the DoD/FEA, no intervenor contested these provisions of the Stipulation or the testimony of Company witness McGee that supports the base fuel and fuel-related cost factors therein. The Commission agrees with the Company that the concerns raised by witness Mancinelli are better addressed in the Company's annual fuel proceeding. Accordingly, the Commission finds and concludes that the base fuel and fuel-related cost factors as set forth in Section IV.C. of the Stipulation, as well as the adjustments to this factor agreed to therein, are just and reasonable to all parties in light of all the evidence presented for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

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

The Company's proposed adjustment for coal inventory, as reflected in its Form E-1, Item 10, Adjustment NC-1600, set the inventory balance to 40 days of 100% full load burn, resulting in a reduction to the materials and supplies component of cash working capital in this case. (Tr. Vol. 7, p. 298.) This is the level of coal inventory that was utilized in DEP's last general rate case for the materials and supplies component of cash working capital, and was stipulated by the Public Staff and the Company in the settlement agreement approved by the Commission in that case. (Id.)

In his pre-filed testimony, Public Staff witness Metz recommended adjustment to the materials and supplies component of cash working capital to reflect a 30-day coal inventory based on a 70% full load burn. (Id. at 304.) 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 304-05.) Witness Metz based his recommendation of 30 days on the fact that the Company has operated with 40 days or less of inventory in the past, as well as his belief that the Company "is fully capable of operating its plants with 30 days or less of coal inventory." (Id. at 306.)

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. 10, p. 37.) 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 a targeted 40-day, 100% full load burn. (Id.)

Witness Miller testified that adopting witness Metz's recommendation of 30-day coal inventory based on a 70% full load burn could lead to negative supply, delivery, and operational impacts. (Id. at 36.) He testified further that this 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 38.) 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.) According to witness Miller, if DEP 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. at 45.) As such, having unreliable coal inventory levels could result in unfavorable impacts on customers. (Id.)

Witness Miller stated that while the Company acknowledges that it does not consistently achieve and maintain a 40-day full load burn inventory level, as a number of factors cause actual inventory to fluctuate over time, DEP does not agree that it has demonstrated it is "fully capable of operating its plants with 30 days or less of coal inventory" as witness Metz suggests. (Id. at 44.) Witness Miller explained that a 30-day, 70% capacity factor equates to a 21-day full load burn at 100% during periods of peak demand. (Id. at 40-41.) Given typical transit time from mine to plant during times of increased demand, inventory could be depleted to unreliable levels for coal generation. (Id. at 41.) Witness Miller concluded that the Company does not believe that the proposed 30-day, 70% capacity factor inventory target is prudent and would negatively impact the Company's ability to continue providing reliable, cost-effective generation for its customers. (Id. at 45.)

In the Stipulation, the Public Staff and DEP agreed that for purposes of settlement, the Company may set carrying costs included in base rates assuming a 35-day coal inventory at 100% capacity factor (full load burn), 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 $76.11 per ton). The rider will terminate the earlier of (a) January 30, 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.[13] 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, concurrently with DEP's DSM/EE Rider, REPS Rider, JAAR Rider, and Fuel Adjustment Rider, and any over- or under-collection of costs experienced as a result of this rider shall be trued up in that annual rider filing. For purposes of the coal inventory rider, the Stipulating

[13] The Stipulation provides that the Company reserves the right to request an extension of the January 30, 2020 date.

Parties agree that interest on any under- or over-collection shall be set at the Company's net-of-tax overall rate of return, as approved by the Commission in this proceeding. 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-2, Sub 1023), with such analysis to be completed by December 31, 2018.

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

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 27-28

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

Company witness Fountain testified that a key area of focus for the Company is customer satisfaction, which the Company measures via a proprietary relationship study. He stated that this study shows that North Carolina residential customer satisfaction scores have risen 10 points since 2013. Witness Fountain also testified that the Company conducts a transaction study to measure satisfaction with how the Company responds to customer service requests. As part of this study, a third-party research supplier conducts interviews with customers. The analysis of these interviews and surveys are used by the Company to implement improvements. Witness Fountain also outlined the efforts of the Company to address language, cultural, and disability barriers in its customer service centers.

Company witness Simpson described metrics the Company uses to measure the effectiveness of its transmission and distribution operations. He provided an overview of the transmission and distribution metrics used to measure the Company's reliability and reduce customer outages. The Company uses the System Average Interruption Duration Index (SAIDI), which indicates how often the average customer has a sustained outage, and the System Average Interruption Frequency Index (SAIFI), which indicates the total duration of an outage for the average customer. Witness Simpson stated that the Company's SAIFI performance is showing a modest improvement, while the Company's SAIDI performance is worsening.

Public Staff witness Williamson noted that the Consumer Services Division of the Public Staff had engaged in approximately 4,854 direct contacts with Company customers during the test year, with the majority of contacts related to payment arrangements and only 3% related to service quality issues. Witness Williamson also addressed the service quality issues related to the SAIDI and SAIFI metrics, noting that the metrics show that while the Company's outages are decreasing in frequency, the outages that do occur are longer in duration.

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

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

DEP proposed several changes to its Service Regulations. Most of the revisions involve relatively small increases or decreases in charges imposed by DEP for various services, such as disconnections and reconnections. Public Staff witness Williamson testified that the Public Staff does not oppose these changes to the Service Regulations.

Witness Williamson further testified that DEP has implemented three changes to its vegetation management plan (VMP): (1) a new flyer on "Hazard Tree Assessment" that allows customers to identify hazard trees, (2) a "Customer Communication Log" that requires contractors to document their communications with customers, and (3) an extension of its non-urban distribution management cycle from six to seven years. With regard to the third point, witness Williamson noted that the Public Staff recommended a $4 million reduction in DEP's revenue requirement due to this lengthened management cycle. He further stated that DEP proposes to continue its urban distribution maintenance cycle at three years, and its transmission maintenance cycle at six years.

In the Stipulation, Sec. III.F., the Public Staff agreed to withdraw its recommended $4 million reduction in DEP's revenue requirement due to the lengthened vegetation management cycle for non-urban distribution.

The Commission gives significant weight to the testimony of Public Staff witness Williamson with regard to the amendments to DEP's Service Regulations and vegetation management plan. Moreover, no other parties filed testimony regarding these matters. Therefore, the Commission finds and concludes that the amendments to DEP's Service Regulations and vegetation management plan are reasonable, serve the public interest, and should be approved.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 29

The evidence supporting this finding of fact and conclusions is contained in the Stipulation, the testimony of DEP witnesses Fountain and Simpson, Public Staff witness

Floyd, CUCA witness O'Donnell, EDF witness Alvarez, and NCSEA witness Golin, and the entire record in this proceeding.

Company witness Fountain testified regarding the $13 billion grid modernization plan for DEP and DEC over the next decade in North Carolina, which has been named Power/Forward Carolinas (Power/Forward). He testified that the purpose of this plan is to improve the performance and capacity of the grid, making it smarter and more resilient and providing customers greater benefit.

Company witness Simpson testified that DEP provides service to over a million customers in North Carolina, where the Company has more than 56,000 miles of lines and nearly 500 substations. (Tr. Vol. 9, p. 21.) He indicated that in the last four years, the Company has spent $1.7 billion dollars maintaining and upgrading that system: $1.2 billion has gone to investments in distribution, while $500 million has been invested in its transmission system. (Id.) Distribution investments include connecting new customers, lighting installations, capacity additions, and infrastructure maintenance and upgrades, while the Company's transmission investments include addressing capacity and compliance projects, as well as replacement of wood poles, obsolete substations, and line equipment. (Id.) Witness Simpson also discussed the need for the Company's customary rate of spend in calendar years 2017 through 2021 to invest in maintenance of the grid and to ready it for new customers. (Id. at 22.)

Witness Simpson explained that despite these investments, DEP's system has been challenged by more severe weather and equipment failures that have manifested themselves in worsening reliability across DEP's grid. (Id. at 21.) Reliability metrics show that the frequency of outages has increased from 1.2 average interruptions in 2014 to approximately 1.3 in 2016. (Id.) The average duration of interruptions has increased approximately 45% since 2013. (Id.) Witness Simpson also noted that the number of events "has gone up 25% in the past four years." (Id. at 103-04.) He projected that in the next ten years, the grid will be challenged by more frequent and severe weather events. At the same time, the grid is aging, with approximately 30% of the Company's infrastructure passing the end of its design life in the next ten years. (Id. at 22.) Witness Simpson indicated that this older equipment, despite being well-maintained, is one of the top drivers for the worsening reliability metrics, as it is more likely to fail when stressed by inclement weather and is more time-consuming to repair. (Id. at 22.)

To address these issues, the Company is beginning to execute its Power/Forward modernization plan to improve the performance and capacity of the grid. (Tr. Vol. 6, pp. 59-60.) While not included in the revenue requirements for this case, as part of the Company's Power/Forward initiative, DEP targets spending $1.6 billion in capital and $62.4 million in O&M over the next five years for North Carolina, from 2017 through 2021, on grid improvements to increase system reliability and hardiness, add customer-focused features, comply with federal standards for security and reliability, replace aging assets, and integrate intermittent distributed renewables. (Id.; Tr. Vol. 9, p. 22.) Witness Simpson testified that these expenditures are necessary to fulfill the Company's mission of providing safe and reliable service for DEP customers. (Id. at 40-41.)

Witness Simpson testified that the Power/Forward initiative will transform the Company's 20th century grid to a state-of-the-art, more reliable and resilient 21st century grid which will benefit customers and the state as a whole. It is a holistic, ten-year program, consisting of targeted undergrounding, hardening and resiliency investments, installation of self-optimizing grid, advanced metering infrastructure, communication network upgrades, and deployment of advanced enterprise systems. (Id. at 109-10.)

Public Staff witness Floyd reiterated that the Power/Forward initiative is not a part of this rate case. (Tr. Vol. 19, pp. 124-25.) However, he further states that should the Company seek recovery of the $18.2 million it has already spent on Power/Forward, it should only be permitted to recover the costs if DEP can demonstrate that the investment was cost-beneficial to customers. (Id. at 126.) Witness Floyd also believes additional reporting is needed to allow the Commission to better understand Power/Forward and to quantify its benefits. Witness Floyd recommended that the Commission require DEP to include in its smart grid technology plan filings, required by Commission Rule R8-60.1, more detailed information. (Id. at 126-27.)

CUCA witness O'Donnell testified that in his opinion, witness Simpson's testimony is lacking a financial cost/benefit study analysis providing evidence demonstrating that the system improvements contemplated as part of the Power/Forward initiative are worthwhile investments. (Tr. Vol. 15, p. 134.) He argued that if DEP cannot provide evidence that service is improving and its grid investment plan is cost-effective, the Commission should question the Company's plan to increase rates to pay for the proposed grid investments. (Id.) O'Donnell requested that the Commission open a docket to investigate the need for DEP's proposed grid investments and examine whether the plan is needed for reliability purposes; whether it is cost-effective; how are other states handling grid modernization; and how will the rate increases expected under DEP's plan affect the state's economy. (Id. at 140.) EDF witness Alvarez also recommended that the Commission establish a distinct proceeding to address and resolve the issues presented by the Company's grid modernization investment proposal. (Tr. Vol. 7, p. 173.) Witness Alvarez noted that, unlike many other states, the Commission has not yet used a rigorous review and stakeholder participation process in its current Smart Grid Technology Plan cases to ensure that utilities get the full "bang for the buck" by maximizing all the available benefits of grid modernization spending. (Tr. Vol. 7, p. 139).

NCSEA witness Golin also recommended a formal and separate process, either through legislative investigation or through Commission docket, to appraise the Power/Forward proposal and include input of all relevant stakeholders to ensure that investments are in the best interest of ratepayers. (Tr. Vol. 13, p. 49.) She also claims that the plan has been developed without engaging any of the best practices of grid modernization, including clear and measurable goals, robust cost/benefit analyses, involving stakeholders, or integrated distribution planning. (Id.)

In response, witness Simpson disagreed with the contention that the Company has not demonstrated that Power/Forward investments will benefit North Carolina customers. He explained that the Company, through experts, quantified the benefits of Power/Forward to the economy of North Carolina and the businesses in its service area, and the study anticipates lower operational costs to the Company over time as a result of the core reliability improvements. (Tr. Vol. 9, p. 62.) In this study by Ernst & Young, included as Simpson Rebuttal Exhibit 1, it is estimated that by 2028 North Carolina businesses will benefit by $1.7 to $2.8 billion per year from reduced outage-related costs and increased profit opportunities. (Id.) Net economic benefits from direct capital investments in the state total between $240 million and $1.4 billion. (Id.) In total, this economic analysis shows that approximately 19,000 jobs will be supported or created statewide through higher levels of economic activity associated with improved reliability and the spending associated with the plan. (Id.) In addition, DEP anticipates ongoing annual cost savings over time resulting from reduced spend on vegetation management, outage restoration activity, and major storm event restoration. (Id. at 62-63.)

An Executive Technical Overview of Power/Forward developed by the Company, which was introduced during the hearing as Duke Progress Simpson Redirect Exhibit 1, also quantifies the benefits of the program, including customer control, choice and convenience; core reliability improvements; statewide economic benefits; and jobs and community growth. (Simpson Redirect Ex. 1, p. 13.)

Regarding intervenor recommendations for a separate proceeding, witness Simpson stated that he is not aware of any pre-approval process for grid investments in North Carolina like utilities have for generation investments. (Id. at 63.) From witness Simpson's perspective, this is no different from the grid planning that the Company has done for years; it is just that timing and the age of the grid require more investment than the Company has historically had to make. (Id.) While the Company is intentionally being transparent in its plans relating to Power/Forward, both in customer communications as well as in discussions and discovery in this case, the Company does not believe that a separate proceeding is required or advisable. (Id.)

In its post-hearing Brief, the AGO notes that DEP witness Simpson provided a break-down of the planned $13 billion expenditure on grid modernization, as follows:

Targeted underground transmission lines	$4.9 billion
Distribution H&R	$3.5 billion
Transmission	$2.2 billion
Self-optimizing grid	$1.2 billion
Advanced Metering Infrastructure	$ 549 million
Enterprise systems upgrades	$103 million

(Tr. Vol. 9, p. 69.)

The AGO states that it fully supports and applauds DEP's commitment to planning for efficient and effective utility service for its customers, but that the issue is whether DEP has done the necessary work to determine whether this particular approach is a reasonable and prudent way to attack the problem of reliability and security of the grid.

The AGO cites the testimony of Public Staff witness Floyd that "additional reporting is needed to allow the Commission to better understand Power/Forward Carolinas and to quantify its benefits. The extent of the planned investment and the potential impact on customer rates requires additional reporting, in order to assist the Commission and Public Staff in understanding Power/Forward Carolinas and evaluating its cost-effectiveness." (Tr. Vol. 19, p. 127.)

Further, the AGO states that NCSEA witness Golin raised similar concerns, noting that DEP has not performed a cost-benefit or business case analysis. (Tr. Vol. 13, pp. 27, 40; DEP Response to NCSEA DR 5-14/ Golin Direct Exhibit CG-3/Off. Exh. 13, p. 15.) The AGO submits that prior to spending billions of dollars on grid modernization efforts, DEP should be required to demonstrate to the Commission that the money will be spent on appropriate programs. Without taking a position on whether the Commission should open a separate docket, the AGO urges the Commission to enter an order requiring DEP to provide the Commission and the public the information outlined in the testimony of witnesses Floyd and Golin.

In its post-hearing Brief, EDF submits that the Commission should initiate a separate docket for stakeholder input and Commission consideration of DEP's and other utilities' grid modernization plans. EDF states that a review process would allow the Commission to optimize grid modernization investments and maximize the benefits customers receive. Further, EDF states that customers pay for 100% of the utilities' grid modernization spending, so the customers should have a say in the investments/capabilities and receive 100% of the available benefits. In addition, EDF states that DEP ultimately provided a cost-benefit analysis for its Power/Forward proposal, but that the analysis was not provided in sufficient time to allow the parties to study and discuss it. Moreover, EDF opines that DEP's analysis included only operational benefits and did not include benefits from integrating renewable resources or increased opportunities for energy efficiency and peak demand reductions. EDF states that the testimony of witness Alvarez, which EDF summarized in its Brief, supports EDF's recommendations.

Paragraph IV.A. of the Stipulation provides that DEP will host a technical workshop during the second quarter of 2018 regarding the Company's Power/Forward planned grid investments. The Stipulation further provides that Public Staff involvement in the workshop in any capacity does not preclude it from investigating or making recommendations regarding any element of the Company's Power/Forward program in a future rate case or pursuant to any applicable statutes or Commission rules. Further, the Commission is not precluded from considering or reviewing any aspect of the Power/Forward program in separate dockets as it determines appropriate, nor does it preclude the Public Staff's participation in such dockets. The Commission notes that the Company is not seeking recovery of investments relating to Power/Forward in this rate case. Ultimately, the burden of proof is on the Company to support the prudence of investments in grid modernization if and when it seeks cost recovery of such investment. That burden of proof is not required in the current proceeding. Based on the full record in this docket, the Commission concludes, however, that the Company has not yet provided compelling evidence that the proposed grid investment plan will result in meaningful benefits to ratepayers despite its cost. The Commission acknowledges the potential rate impacts of implementing Power/Forward. CUCA witness O'Donnell testified that he calculated the impact on rates to range from an 8.94% increase for the Company's industrial customers to a 48.74% increase for the Company's residential customers. (Tr. Vol. 15, p. 131.) Existing dockets (such as Integrated Resource Planning and Smart Grid Technology Plans) as well as future general rate case proceedings provide opportunities for the Commission to consider evidence evaluating the prudency and reasonableness of Power/Forward costs.

No parties objected to the technical workshop, its timing, or the conditions regarding the Public Staff or Commission. The Commission finds this provision of the Stipulation to be just and reasonable.

In its post-hearing Brief, EDF submitted that the Commission should initiate a separate docket for stakeholder input and Commission consideration of DEP's and other utilities' grid modernization plans. The Commission will not open a separate docket for grid modernization planning and/or revisions to existing Commission rules at this time. Rather, the Commission will reconsider such proposals pending the effectiveness of the technical workshop, the outcome on this issue in DEC's general rate case proceeding (Docket No. E-7, Sub 1146), Integrated Resource Planning, and Smart Grid Technology Plans to evaluate grid investment plans.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 30

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

As part of its filing in this case, the Company submitted a lead-lag study that was performed in 2011 using fiscal year 2010 data. (Tr. Vol. 10, p. 91; Doss Ex. 3.) Public Staff witness Peedin commented that the Public Staff believes that a fully updated lead-lag study should have been completed for this case and recommended that the Commission direct the Company to prepare and file a lead-lag study in its next rate case. (Tr. Vol. 18, p. 81.) In his rebuttal testimony, DEP witness Doss stated that the Company agrees with Public Staff witness Peedin's recommendation and testified that DEP will prepare and file an updated lead-lag study as part of its next rate case application. (Tr. Vol. 10, p. 91.)

The Stipulation incorporates the Company's agreement to file an updated lead-lag study in its next rate case. No other party filed testimony on this issue. Accordingly, the Commission finds and concludes that, consistent with Section IV.E. of the Stipulation and in light of all the evidence presented, DEP shall prepare and file a lead-lag study in its next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 31-32

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

Company witness Hager's direct testimony describes and supports the Company's Summer Coincident Peak (SCP) cost of service study. Witness Hager recommended the use of the SCP as a fair allocation of the costs to the appropriate jurisdiction and customer class. As articulated by witness Hager, the cost responsibility of each jurisdiction and customer class should be determined on its respective demand in relation to the total demand placed on the system.

The Company's summer peak occurred on Tuesday, July 26, 2016, at the hour ending at 5:00 p.m. The Company's system peak occurred on Tuesday, January 19, 2016 in the hour ending at 8:00 a.m. Witness Hager noted that although in 16 of the last 25 years the coincident peak for the system occurred in June through August, the majority of peaks in the past eight years has occurred in the winter. Even though the Company's peak occurred in the winter and the majority of the recent peaks have occurred in the winter, witness Hager asserted that the production and transmission demand-related costs allocated in this case were incurred on the basis of integrated resource planning that was based on a summer peak and that they should be allocated based on the summer peak.

The Public Staff historically has supported the use of the Summer/Winter Peak and Average (SWPA) cost of service allocation methodology. As noted in witness Floyd's testimony, the SWPA methodology recognizes that a portion of plant costs is incurred to meet the energy costs throughout the year, and not just at the time of the peak. However, under the particular circumstances of this case, Public Staff witness Floyd did not object to the Company's use of the SCP methodology for determining the cost of service due to the small difference in the per books calculation between SCP and SWPA. Based on the testimony of witness O'Donnell, CUCA also supports use of the SCP methodology.

CIGFUR witness Phillips and DoD/FEA witness Mancinelli testified in opposition to the Company's use of the SCP methodology. Witness Phillips testified that because DEP has transitioned from a summer peaking to a winter peaking utility over the last several years, he recommends that the Winter Coincident Peak (WCP) methodology be used in this case. (Tr. Vol. 7, p. 65.)

DoD/FEA witness Mancinelli asserted that DEP's proposal to utilize a SCP method to allocate production and transmission demand costs to its customer classes is a flawed method since it does not recognize DEP as a dual peaking system. (Tr. Vol. 17, pp. 136-37.) He argued that the Company should use the average of the SCP and WCP to create a 2-CP methodology. (Id. at 134.) He explained that a review of DEP's historical summer and winter peaks confirms that the summer peaks and winter peaks have been very close. (Id. at 138-39.) He argues that this fact, in conjunction with the fact that the difference between summer and winter peaks is projected to remain small through 2030, demonstrates that DEP's system is dual peaking. (Id. at 134.) Therefore, witness Mancinelli argued that the 2-CP methodology is the fairest and most sustainable allocation method because it recognizes the benefit to customer classes that contribute to the summer and winter peaks. (Id. at 137.)

Witness Hager specifically responded to the 2-CP approach advocated by the DoD/FEA, noting that witness Mancinelli confuses duel peaking with dual planning. (Tr. Vol. 10, p. 283.) Witness Hager testified that "[t]he NARUC COS Manual states on page 45 that 2 CP is appropriate if 'the summer and winter peaks are close in value, and if both significantly affect the utility's expansion planning.'" (Id. at 283 (emphasis added).) While witness Hager acknowledged that in 2016 DEP's integrated resource planning transitioned to winter capacity planning, the first identified new resource in the DEP 2017 Integrated Resource Plan that would be added due to this transition is in the 2021/2022 timeframe. (Id. at 284.) Therefore, none of the resources for which the Company is seeking recovery of and on in this proceeding were secured on the basis of a WCP. (Id.)

In the Stipulation, the Public Staff agreed not to oppose the Company's use of SCP for the purpose of settlement in this case only, with the exception of the allocation of coal ash costs. In its settlement agreement with the Company in this proceeding, Kroger stated that it did not oppose the settlement between the Company and the Public Staff on cost of service allocation methodology. Paragraph V.B. of the Stipulation provides that neither the Stipulation nor any of its terms shall be admissible in any court or Commission except to implement its terms and that the Stipulation shall not be cited as precedent by any Stipulating Party with regard to any issue, including cost of service allocation methodology, in any other proceeding or docket. Paragraph V.C. of the Stipulation provides that no Stipulating Party has waived any right to assert any position in any future proceeding or docket.

CUCA, in its post-hearing Brief, states that DEP's use of the SCP allocation methodology is appropriate for use in DEP's cost of service study in the present case because DEP has historically been a summer peaking system.

In its post-hearing Brief, CIGFUR states that it supports the Company's proposal to use a single coincident peak demand allocation methodology for its cost of service study, but rather than the Company's proposed SCP, CIGFUR supports the use of the WCP, which, according to CIFGUR, more appropriately reflects the Company's actual planning peak in accordance with accepted cost allocation principles. CIGFUR states that DEP bears the burden of showing that the use of the SCP is the most appropriate cost allocation method "[b]ased on the evidence in this proceeding." See Order Granting General Rate Increase, Docket No. E-22, Sub 479, at p. 23 (Dec. 21, 2012). CIGFUR contends that while historically DEP based its projected need for resources on the need to meet summer afternoon peak demand projections, the significant growth of solar facilities, which assist with meeting summer afternoon peak demands on the system, but do little to accommodate demand on cold winter mornings, and the associated impact on summer versus winter reserves, have led DEP to experience a dominant winter peak for six out of the last eight years. CIGFUR notes that the Company now uses the winter peak for system planning, including calculation of reserve margin, and determining its need for additional generation facilities. (Tr. Vol. 7, p. 65.) Further, according to CIGFUR, DEP is forecasted to remain winter-peaking through 2032, which marks the end of the planning horizon.

CIGFUR contends that even though it is undisputed that the Company is winter-peaking and plans its generating capacity accordingly, the Company, through witness Hager, proposes to allocate production and transmission demand-related costs on the SCP on the premise that the costs being allocated in this case were incurred on the basis of summer planning (Tr. Vol. 10, p. 292; Tr. Vol 11, p. 137), and that for the following reasons the Company's argument is without merit:

(1) The Company's use of the SCP method is inconsistent with the NARUC Cost of Service manual. (Tr. Vol. 17, p. 137.)

(2) The Company does not cite any precedent within this State for its novel proposal to employ a 1 CP cost of service study based on its historical peak rather than its current planning peak.

(3) The Company's cost of service study choice has significant negative impacts on the LGS class. (Tr. Vol. 11, pp. 135-36.) CIGFUR includes a table that it contends demonstrates that the LGS class's rate of return is below North Carolina retail under the SCP methodology, but at or above North Carolina retail under the WCP and 2 CP methodologies.

(4) After rate design, the Company's choice to allocate production and transmission demand-related costs on the SCP results in lower rates for residential consumers, but at the expense of large load customers.

(5) Although the Company has been winter peaking since 2013 and will be winter-peaking for the foreseeable future, it has not identified when it will shift its cost of service study to recognize the winter peak. (Tr. Vol 11, pp. 20-21.)

(6) The winter peak is the capacity planning basis of DEP's system and therefore the cost causation for its production plant.

CIGFUR states that if the Commission is reluctant to approve the WCP cost study because of the recentness of the transition from summer to winter planning, a second option is the use of the 2 CP cost of service study, which is discussed by witnesses Phillips (Tr. Vol. 7, p. 66), and Mancinelli. As witness Mancinelli noted, "[a]lthough the actual system peak hour occurs during the winter, the magnitude of the winter peak is very close to the magnitude of the summer peak." (Tr. Vol. 17, p. 138.)

The Commission recognizes that cost causation is the primary driver and support for choosing an appropriate cost allocation methodology. The Commission also understands that there is an element of subjectivity in this choice. The Commission finds and concludes that the SCP is the appropriate cost allocation methodology, for the purposes of this proceeding, subject to the provisions of the Stipulation. The Commission gives substantial weight to the testimony of Company witness Hager's assertion that the production and transmission demand-related costs allocated in this case were incurred on the basis of integrated resource planning that was based on a summer peak and that they should be allocated based on the summer peak. The Commission notes that the difference between the SCP and WCP in the test year was minimal (1%) and that the Company has committed to monitoring the system peak information for consideration in future cost of service studies. Further, the Commission finds that the recent convergence of SCP and WCP experienced by the Company is adequately accounted for in the stipulated rate design.

Although the Public Staff has traditionally supported SWPA cost allocation, it is not unreasonable for the Stipulating Parties to have agreed to the use of SCP for this proceeding. Based on DEP's Late-Filed Exhibit 5 and the Public Staff's Late-Filed Exhibit 1, the Commission determines that the difference in retail revenue requirements for the SCP methodology compared to the SWPA methodology is insignificant. The Commission acknowledges the Public Staff's position on cost allocation, but views its position relative to the Stipulation as just and reasonable to the using and consuming public that the Public Staff represents. Therefore, based upon consideration of the Stipulation in its entirety, the Commission gives the Stipulation substantial weight in resolving the cost allocation issue. However, the Commission's acceptance of the SCP methodology in this proceeding shall not be precedent for and may not be cited as such in future proceedings.

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

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 33-34

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

Company witness Wheeler provided testimony regarding the Company's proposed changes to rate design. He developed the Company's proposed rates by first determining the target total proposed change in revenue requirement for each class, then designing the rate schedules and riders in each rate class to total the proposed change in the revenue target for that rate class. Witness Wheeler's proposed rate design did not propose any substantial changes to the structure of any of its rate schedules in this proceeding. He explained in his direct testimony that the Company plans to implement rate design changes once it has deployed AMI and has updated its billing structure to better support peak time pricing rate design.

Witness Wheeler recommended adjusting seasonal and time-of-use (TOU) price relationships by reducing the emphasis on on-peak energy rates due to the narrowing of the difference between on-peak and off-peak marginal energy costs and by reducing the emphasis on summer pricing in the energy rates. As a result, the rates designed by witness Wheeler narrow the difference between on-peak and off-peak charges for TOU rates.

Witness Wheeler also recommended increasing the basic customer charges (BCCs) for various rate classes. For the Residential Rate Class, he recommended increasing the BCC to $19.50 for schedule RES and increasing the BCC to $22.35 for Schedules R-TOUD and R-TOU. Witness Wheeler also recommended increasing the BCC for SGS schedules to $22.50.

In Section IV.F.3 of the Stipulation, the Stipulating Parties agreed to implement the rate design proposed by Company witness Wheeler, subject to the following modifications:

a. The Stipulating Parties agree that the Company may increase its Basic Customer Charge for Schedule RES to $14.00 per month. The Stipulating Parties further agree that the Company may increase its Basic Customer Charges for Schedules R-TOUD and R-TOU to $16.85 per month.

b. The Stipulating Parties agree that the Company will maintain the current differential between the on- and off-peak energy rates in all of its time-of-use rate schedules when assigning the revenue requirement approved in this proceeding.

c. The Stipulating Parties agree that the rates set forth in the minimum bill provisions of the MGS class schedules shall be set at the class approved unit energy and demand cost as proposed by the Company, but shall also be adjusted to reflect all riders applicable to service under the schedule.

d. To ensure a more equitable impact on the MGS class, the Stipulating Parties agree that the revenue increase applicable under Schedules MGS and SGS-TOU should strive to achieve approximately the same percentage increase in revenues under each schedule.

Additionally, the Company entered into settlement agreements with Commercial Group and Kroger regarding rate design issues. Commercial Group and Kroger agreed to settle all issues with the Company, provided that, inter alia, the Stipulation between the Company and the Public Staff state that "the revenue increase applicable under Schedules MGS and SGS-TOU should strive to achieve approximately the same percentage increase in revenues under each schedule." (Kroger Settlement 1; Commercial Group Settlement 2; Stipulation IV.F.3.d.) Moreover, as part of the Commercial Group Settlement, "DE Progress agrees that it shall work with interested commercial and industrial customers to investigate the issues with Rider SS that were raised in the direct testimony filed by the Commercial Group." (Commercial Group Settlement 2-3.)

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.

Basic Customer Charge

As explained above, DEP has requested that the BCC for all of its rate classes be increased to varying degrees to better recover customer-related costs identified in the unit cost study. (Tr. Vol. 10, pp. 199-211.) Specifically, the Company proposed changing the BCC for Schedule RES from $11.13 to $19.50 to reflect approximately 50% of the difference between the current rate of $11.13 and the customer-related cost of $27.82 identified in the unit cost study. (Id. at 220.) The Stipulation provides for a BCC of $14.00 for Schedule RES and $16.85 for Schedules R-TOUD and R-TOU. (Stipulation IV.F.3.a.) The Stipulating Parties also agreed to the increases in the BCCs requested by the Company for the remaining rate classes.

Several intervenors provided testimony regarding the Company's proposed increases to the BCCs. Public Staff witness Floyd testified that the residential BCC should only increase 25%, or to approximately $15.00 for Schedule RES. (Tr. Vol. 19, p. 105.) While the Public Staff generally agrees with the Company's proposal to move the BCC toward its calculated unit cost, witness Floyd explains that the increase should be smaller to moderate the impact on low usage customers. (Id.) Witness Floyd believes that DEP's requested increase is unreasonably large given the fact that the Company received an increase in the BCC in its last rate case in Docket E-2, Sub 1023, which accounted for 74% of the total revenue increase the Company was allowed to derive from the residential class, and the BCC increase requested by the Company in the current rate case would account for approximately 45% of the revenue increase from residential customers. (Id. at 104.)

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. 16, p. 49.) Specifically, NCSEA witness Barnes testified that the increased Residential BCC proposed by the Company was higher than other utilities and is, therefore, inappropriate. (Id. at 49-52.) Witness Barnes also argues that the proposed increases are inconsistent with the ratemaking principle of gradualism. (Id. at 52-53.)

Witness Barnes, as well as NC Justice Center witness Wallach, also assert that an increase in the customer charge dilutes customer incentives for distributed generation and energy efficiency. (Tr. Vol. 16, pp. 53-55; Tr. Vol. 17, p. 206.) The Commission gives significant weight to witness Wheeler's rebuttal testimony in response to this argument. Witness Wheeler explained that "[f]ailing 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." (Tr. Vol. 10, p. 222.) In addition, he testified that shifting fixed customer-related cost to the volumetric energy rate exacerbates this concern and over-compensates energy efficiency and distributed generation for the cost avoided by their actions. (Id.) Further, the Commission determines that existing energy efficiency programs are effective, and it is not persuaded that it needs to further support energy efficiency by refusing to approve an appropriate increase in the BCC.

Witness Wallach explained the intent behind basic customer charges as follows: basic customer charges are intended to recognize that each customer contributes equally to certain distribution costs regardless of that customer's energy usage. The fixed customer charge should, therefore, be set to recover the cost to connect the customer to the distribution system – more or less. These customer-related connection costs are limited to plant and maintenance costs for a service drop and meter, along with meter reading, billing, and other customer-service expenses. (Tr. Vol. 17, pp. 213-14.) In response to a NC Justice Center et al. data request, DEP re-ran its cost-of-service study without the minimum system analysis, excluding pole, conduit, conductor, and line transformer costs as demand-related rather than customer-related. As a result of excluding those costs attributable to the minimum system analysis, the Company's estimate of customer-related costs was only $8.54. (Tr. Vol. 11, pp. 58-59, Hager; Tr. Vol. 17, pp. 203, 215, Wallach); NCJC Hager/Wheeler Cross Ex. 1 (Ex. Vol. 20, p. 123.)) Witness Wallach testified that DEP's modified cost-of-service study shows that a sizeable portion of demand-related distribution plant costs are inappropriately being recovered through the current basic customer charge. The amount in excess of $8.54 represents usage-driven costs that should be recovered in the volumetric energy rate, so that each residential customer contributes to recovery of these costs in direct proportion to his usage. (Tr. Vol. 17, pp. 215-16.)

Although a utility's cost-of-service study serves as the foundation for its rate design, this Commission has recognized that the two are distinct. See, e.g., Order Granting Partial Increase In Rates and Charges, Docket No. E-2, Sub 526, at pp. 29-30 (Aug. 27, 1987) (approving use of minimum system for cost allocation, but not for rate design); Order Granting General Rate Increase, Docket No. E-2, Sub 1023 (May 30, 2013), at p. 32 (Sub 1023 Order) ("the Commission regards any increase in the BCC as a rate design issue, not an ROE [rate of return on equity] issue.") DEP witnesses Hager and Wheeler, although at times conflating cost-of-service study issues with rate design issues, also acknowledged that rate design requires consideration of issues beyond cost of service. According to witness Wheeler, "[the] cost of service [study] provides [the rate designer] customer-related, demand-related, and energy-related costs. In efficient rate design, we try to separately distinguish those costs . . . and try to have rates that would recover those costs appropriately based on cost causation." (Tr. Vol. 11, p. 62.) Witness Hager acknowledged that there is "not always a pure translation from cost of service studies to rates." (Tr. Vol. 10, p. 328.) Witness Floyd also recognized that rate design, and specifically, setting the BCC, requires consideration of other factors besides cost of service: "It is up to the rate designer to take into account all these other issues that are outside of cost of service in coming up with where that basic customer charge should land." (Tr. Vol. 19, p. 160.)

Witness Wallach agreed that rates should be based on principles of cost causation; however, he testified that DEP's use of the minimum system technique in its cost of service study inappropriately classifies a portion of distribution plant costs as customer-related. (Tr. Vol. 17, p. 201.) As witness Wallach explained, "it is not appropriate to rely on the results of minimum system analyses to estimate per customer minimum plant costs, since such analyses typically overstate the true minimum cost per customer for distribution plant." (Tr. Vol. 17, p. 200.) This is because some portion of distribution plant costs are driven by usage, yet the minimum system technique incorrectly classifies those demand-related costs as customer-related costs, resulting in an inflated estimate of the per-customer minimum plant cost. (Tr. Vol. 17, p. 214.)

The Commission rejected in prior orders use of the minimum system technique to design the basic customer charge for the very reasons cited by witnesses Barnes and Wallach in this case. In Docket No. E-2, Sub 526, a general rate case filed by DEP's predecessor utility Carolina Power & Light (CP&L), the Commission approved the use of the minimum system technique for purposes of allocating costs to the various customer classes, but explicitly rejected its use for purposes of setting the BCC. The Commission explained its decision as follows:

> The minimum system technique derives the cost of distribution plant as if all components of such plant are "minimum" size (i.e., the minimum size needed to connect each customer to the system regardless of the amount of kWh used). The cost of the "minimum" distribution plant is then allocated between customer classes on a per customer basis, while the remainder of the distribution plant cost is allocated between customers on the basis of distribution level kW demand. The Company contended that the allocation of a portion of distribution plant on a per customer basis should result in such distribution cost per customer being reflected in the basic customer charge in order to be consistent with the allocation methodology. However, such reflection of minimum distribution plant costs in the basic customer charges would result in residential customer charges at least double the current $6.65 per month, and the Commission has never approved residential customer charges approaching the levels indicated by the minimum system technique.

Order Granting Partial Increase In Rates and Charges, Docket No. E-2, Sub 526, at pp. 29-30 (Aug. 27, 1987) (emphasis added).

Witness Deberry also opposed the increased residential BCC, testifying that it will affect already cost-burdened residents who struggle to afford housing costs. (Tr. Vol. 13, p. 214.) Witness Deberry explained that over half of all cost-burdened households are renters without the ability to make investments in energy efficiency. (Id. at 216.) She further explained that the increased BCC would reduce incentives from bill savings for landlords to include utility programs in their property management, and, thus, the costs of an increased BCC would be passed on to customers least able to afford it. (Id. at 219.)

Similarly, witness Howat testified that increasing fixed customer charges causes disproportionate impacts to low-volume, low-income customers and discourages energy efficiency. (Tr. Vol. 13, p. 239.) Witness Howat testified that low-income households, and particularly low-income households of color, are at a heightened risk of loss of home energy service, and the increased threat of disconnection posed by the Company's rate increase proposes a threat to the health and safety of these customers and the larger community. (Id. at 247-49.)

In his rebuttal testimony, Company witness Wheeler responded to the arguments raised by these intervenors regarding the proposed increases to the BCCs. (Tr. Vol. 10, pp. 220-24.) 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." (Id. at 220.) Witness Wheeler 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 BCC is shifted to energy rates, which contrary to witness Wallach's assertion, actually results in high-usage customers subsidizing the rates of lower-usage customers. (Id.)

Witness Wheeler also notes that the Company has carefully examined its costs and identified customer-related costs in order to determine the proposed BCCs, and that other utilities' costs and rates are not relevant to the determination of DEP's rates. (Tr. Vol. 10, p. 222.) Witness Wheeler rebutted witnesses Barnes' and Wallach's argument that the BCC discourages distributed generation and energy efficiency. (Id.) Witness Wheeler stated that failing to properly recover customer-related cost via a fixed monthly charge provides an inappropriate price signal to customers and fails to adequately reflect cost causation. Further, he noted that the current residential "energy-only" rate design is already less efficient than ideal because it recovers demand-related cost via a volumetric charge. 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.) DEP witness Wheeler also testified that the Company is mindful of the impact of the rate increase on its low-income customers, and that it has not requested a residential BCC that reflects the fully justified customer-related cost for that reason. (Tr. Vol. 10, pp. 221-23.) Witness Wheeler makes clear, however, that contrary to the assertions of witnesses Howat and Deberry, he believes that biasing rate design is not the most effective way to address the financial needs of these customers, and that rate design must be based on cost causation principles. (Id. at 223.) Instead, there are Company, state, and federal programs which are designed to aid low-income customers. (Id.) For example, the Company offers the Neighborhood Energy Saver Program and various payment plans to assist low-income customers. (Id.) DEP also promotes the Energy Neighbor Fund, which raises funds for local aid agencies to assist low-income customers. (Id.)

At the hearing, witness Wheeler testified on redirect that the BCC increase that the Company has requested, through the Stipulation, would equate to 9 cents per day. (Tr. Vol. 11, p. 149.) He also testified on redirect that even though some of DEP's customers cannot afford an extra dime a day for their BCC, it is still appropriate to increase the BCC because it sends the appropriate price signal to customers about the true cost of electricity. (Id. at 150.) He explained that understating the customer charge shifts to other customers the costs they have to pay, inflates the energy price, and overcompensates customers for energy efficiency and distributed generation resource installation. (Id.)

Additionally, Commissioner Brown-Bland asked how the Company determines whether the increase in BCC would be “rate shock,” particularly to a low-usage customer or net metering customer. (Tr. Vol. 12, pp. 20-21.) In response, witness Wheeler explained that the Company designs rates to send the appropriate price signal and that underpricing the customer charge is a disservice to customers because someone else is paying their fair cost of service. (Id. at 21.) On redirect, witness Wheeler further stated that the Company has requested to increase the BCC by $2.87 per month, as agreed in the Stipulation, and that he does not believe that an increase of that amount would constitute “rate shock.” (Id. at 31.)

NC Justice Center, in its post-hearing Brief, reviews the statutes and case law underlying the requirement of just and reasonable rates. NC Justice Center submits that the $14.00 BCC agreed upon in the Stipulation is unjust and unreasonable. It maintains that the $14.00 BCC would exceed the minimum cost to connect a customer to DEP’s distribution system and would be a disincentive to energy efficiency. NC Justice Center cites the testimony of witness Wallach explaining the intent behind the BCC, and states that DEP did not present sufficient evidence to support an increase to $14.00, noting that DEP relied on the minimum system technique, a technique that NC Justice Center contends the Commission has rejected at least twice as the basis for setting the BCC. It notes that DEP witnesses Hager and Wheeler, as well as Public Staff witness Floyd, acknowledged that rate design requires consideration of issues beyond cost of service.

NC Justice Center states that witness Wallach testified that DEP’s use of the minimum system technique in its cost of service study inappropriately classifies a portion of distribution plant costs as customer-related. (Tr. Vol. 17, p. 201.) Further, it cites the Commission’s 1987 Order in a general rate case filed by DEP’s predecessor, CP&L, and states that the Commission explicitly rejected use of the minimum system technique for purposes of setting the BCC. (Order Granting Partial Increase In Rates and Charges, Docket No. E-2, Sub 526, at pp. 29-30 (Aug. 27, 1987)).

In addition, NC Justice Center states that in CP&L’s next general rate case the Commission again explicitly rejected the minimum system technique for setting the BCC. Order Granting Partial Increase In Rates and Charges, Docket No. E-2, Sub 537, at pp. 130-31 (Aug. 5, 1988)

Moreover, NC Justice Center contends that DEP’s own analysis demonstrates the flaws inherent in using the minimum system technique to establish the BCC, and that it demonstrates that the BCC should not only not be increased, but that it should actually be reduced from its current level. In response to an NC Justice Center data request, DEP re-ran its cost-of-service study without the minimum system analysis, excluding pole, conduit, conductor, and line transformer costs as demand-related rather than customer-related. As a result of excluding those costs attributable to the minimum system analysis, the Company's estimate of customer-related costs was only $8.54, not $27.82. (Tr. Vol. 11, p. 58-59 (Hager); Tr. Vol. 17, pp. 203, 215 (Wallach.) NCJC Hager/Wheeler Cross Ex. 1, (Ex. Vol. 20, p. 123.) NC Justice Center argued, as witness Wallach testified, that DEP's modified cost-of-service study shows that a sizeable portion of demand-related distribution plant costs are being inappropriately recovered through the current BCC. The amount in excess of $8.54 represents usage-driven costs that should be recovered in the volumetric energy rate, so that each residential customer contributes to recovery of these costs in direct proportion to his usage.

NC Justice Center also contends that increasing the BCC to $14.00, as proposed in the Stipulation, would likewise be unjust and unreasonable. Summarizing DEP's and the Public Staff's testimony in support of the Stipulation, NC Justice Center maintains that there was no attempt to explain why a $14.00 BCC is just and reasonable. On the other hand, according to NC Justice Center, witness Wallach testified that the reduced increase in the BCC under the Stipulation does not address his concerns.

Further, NC Justice Center submits that any increase in the residential BCC would disproportionately impact low-usage customers, discourage the efficient use of electricity, in contravention of state law and policy, and shift costs away from higher-volume electricity users within the residential class to lower-volume users in the class. (Tr. Vol. 13, pp. 278-89.) It states that some cross-subsidization is inherent and unavoidable in average-cost ratemaking, as recognized by witnesses for various parties, e.g., DEP witness Wheeler (Tr. Vol. 12, pp. 21-22), but that rates should be designed to minimize cross-subsidization to the extent possible, as a matter of sound public policy, and also consistent with the prohibition on undue discrimination in ratemaking.

NC Justice Center further points to witness Deberry's testimony about the difficulty low-income North Carolinians have in securing affordable housing, and to witness Howat's testimony that the proposed increase in the BCC would be unfair to low-volume customers in DEP's service territory. Also, witness Howat testified that the best available data demonstrates that on average, low-volume users - those who would be most hurt by increases in the basic customer charge - are disproportionately households headed by low-income, African-American, and senior-citizen residents. (Tr. Vol. 13, pp. 241-45.) In addition, NC Justice Center summarizes the public witness testimony regarding the hardship of increases in fixed charges to low-income households, fixed-income households, and senior citizens. NC Justice Center states that these are considerations that the Commission must take into account in this case, citing the statement that "[i]n establishing fair rates to consumers the Commission takes into account the economic conditions in which the consumers find themselves." Order on Remand, Docket No. E-7, Sub 989, at p. 23 (Oct. 23, 2013); and G.S.62-133(a). It also opines that it is in large part because of the 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, and cites NASUCA Resolution 2015-1 (NC Justice Center Floyd Cross Exhibit 1, Ex. Vol. 19, p. 286), which 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."

NC Justice Center cites three decisions in which it submits that the public utility commissions in Maryland, New Mexico, and Michigan, employing the just and reasonable standard, take into consideration how increases in fixed customer charges would affect low-income customers. It asserts that DEP presented no evidence about the effect of an increase in fixed charges on the ability of its most vulnerable customers to maintain essential electrical service. Further, NC Justice Center contends that DEP has not done anything to mitigate its proposed increase in the BCC with additional investments in low-income energy efficiency. It states that after reviewing the amount of DEP's current budget for low-income energy efficiency programs, witness Howat recommended that the Company increase its budget for programs targeted to low-income households from $1.9 million to $11.5 million, an amount more commensurate with the revenue received by DEP from income-eligible households in its service territory (Tr. Vol. 13, pp. 254-58), or follow the recommendation of public witness Goodson that DEP make an annual shareholder contribution to the Helping Home Fund.

In its post-hearing Brief, the AGO contends that DEP's proposal to increase the monthly basic customer charge for residential customers by 26%, from $11.16 per month to $14.00 per month, should be denied because it will discourage consumers from making investments in energy efficient products and home improvements, and from taking other careful measures to budget their consumption, contrary to statutory public policy goals favoring energy efficiency and energy conservation. Moreover, according to the AGO, the increased BCC will shift costs to small users such as low-income and elderly consumers who live in small apartments, as they are charged the same unavoidable BCC as other residential consumers who live in spacious high-consumption residences.

In addition, the AGO contends that energy efficiency and energy conservation are encouraged by a rate design that sets the unavoidable BCC as low as possible and recovers most of the cost of service in the usage charge, and that the effect of the Company's proposal runs contrary to several statutorily declared North Carolina public policies relating to public utilities regulation that favor the encouragement of energy efficiency, energy conservation, and well-planned utility resource development, including:

> (3a) <u>To assure that resources necessary to meet future growth</u> through the provision of adequate, reliable utility service <u>include use of</u> the entire spectrum of demand-side options, including but not limited to <u>conservation</u>, load management <u>and efficiency programs</u>, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning <u>and</u> <u>fixing of rates</u> in a manner <u>to result in the least cost mix of generation and demand-reduction measures</u> which is achievable, <u>including</u> consideration of appropriate <u>rewards to utilities for efficiency and conservation which decrease utility bills</u>;

> (4) To provide just and reasonable rates and charges for public utility services without unjust discrimination, undue preferences or advantages, or unfair or destructive competitive practices and consistent with long-term management and conservation of energy resources by avoiding wasteful, uneconomic and inefficient uses of energy;
>
> ***
>
> [6) To foster the continued service of public utilities on a well-planned and coordinated basis that is consistent with the level of energy needed for the protection of public health and safety and for the promotion of the general welfare as expressed in the State energy policy;
>
> ***
>
> (10) To promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS) that will do all of the following:
>
> a. Diversify the resources used to reliably meet the energy needs of consumers in the State.
>
> b. Provide greater energy security through the use of indigenous energy resources available within the State.
>
> c. Encourage private investment in renewable energy and energy efficiency.
>
> d. Provide improved air quality and other benefits to energy consumers and citizens of the State.

G.S. 62-2(a) (emphasis added).

Further, the AGO states that witness Wallach, an expert who has consulted on electric utility industry matters for over 30 years, estimated that consumption would increase by 2% over the next several years if DEP's initial proposal to charge $19.50 per month is allowed. (Tr. Vol. 17, pp. 209-10, 216.) The AGO states that the smaller increase proposed in the Stipulation is not as discouraging, but still reduces the incentive to conserve and lengthens the time for recoupment of investments by consumers in more energy-efficient home improvements and appliances – particularly given that the 26% increase in the charge is proposed so soon after a 65% increase to the BCC took effect in 2013. (Tr. Vol. 17, pp. 209-210.) In addition, the AGO states that witness Wallach evaluated the cost studies used by DEP and recommended decreasing the BCC to $8.54. (Tr. Vol. 17, p. 215.)

The AGO stated that questions posed by the Commission during the expert witness hearing raised several additional considerations. First, the cost studies that are used to allocate costs among different customer classes are not well suited to determine rate design issues (Tr. Vol. 17, pp. 221-222), and data used to allocate costs over many customers may distort results when applied on a per-customer basis. (Id.) Furthermore, the design of rates carries important ramifications for policies such as the incentives that encourage energy efficiency, conservation, load shifting, etc.

The Commission concludes that the stipulated BCC increases, including a BCC of $14.00 for Schedule RES and $16.85 for Schedules R-TOUD and R-TOU, are just and reasonable and strike an appropriate balance that provides rates that more clearly reflect actual cost causation and, thus, minimize subsidization and provide proper price signals to customers in the rate class, while also moderating the impact of such increase on low-usage customers.

AMI Enabled Rates

NCSEA witness Barnes testified that it is impossible to say that customers will benefit from the Company's proposed AMI deployment because the Company has not provided any detail regarding the rate options that will be offered. (Tr. Vol. 16, pp. 75-78.) Similarly, EDF witness Alvarez also 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. 7, p. 161.) Company witness Wheeler responded that "[i]t would be premature to offer a specific rate design before the infrastructure to support the design is available." (Tr. Vol. 10, p. 227.) Public Staff witness Floyd agreed that the Company's proposal to develop new rate designs after AMI deployment was a "reasonable approach" and testified that the Public Staff is willing to work with the Company to develop these future rate designs. (Tr. Vol. 19, pp. 103-04.)

Additionally, EDF witness Alvarez testified about various AMI-enabled services that he argues offer significant customer and environmental benefit potential. (Tr. Vol. 7, pp. 152-54.) Company witness Wheeler responded that the Company is considering all of the initiatives suggested by witness Alvarez. (Tr. Vol. 10, p. 225.) Specifically, the Company already offers some time varying rates, is evaluating introduction of various usage alerts as part of its Enhanced Basic Services initiative, and has explored residential prepayment options through two different pilot programs. (Id. at 226.) Witness Wheeler 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 227.) 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. at 227-28.)

Witness Wheeler further explained why it would be premature to offer a specific AMI-enabled rate design in this proceeding. (Tr. Vol. 10, p. 227.) In addition to the fact that 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.) For example, witness Wheeler explained that residential appliance control is an effective tool to reduce air conditioning load during system peak conditions which would potentially be the same load shifted by a residential critical peak pricing or peak time rebate program. (Id.) He explained that all customer options need to be evaluated to achieve the most dependable load response at the lowest cost to ratepayers. (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 that if and when DEP's AMI technology and new billing systems are implemented, the Company will be able to evaluate all customer options in order to achieve a rate design that provides the most cost-effective and dependable service to ratepayers.

TOU

In its Application, the Company also proposed adjusting TOU rates to reduce the difference between on-peak and off-peak rates. (Tr. Vol. 10, p. 228.) Witness Wheeler explained that this change reflects the ongoing trend of a declining differential between on-peak and off-peak marginal energy cost. (Id.) Public Staff witness Floyd recommended deferring this change and maintaining the current differentials between on-peak, shoulder, and off-peak energy rates. (Tr. Vol. 19, p. 107.) Witness Floyd argues that narrowing the difference diminishes the price signal and thereby discourages switching of consumption away from the peak periods. (Id. at 106.) Additionally, he believes it may cause confusion when new and enhanced rate designs are introduced after AMI deployment. (Id.)

NCLM notes that in the Stipulation it is agreed that DEP will host a workshop on Power/Forward during the second quarter of 2018 and will report the results of the workshop to the Public Staff and the Commission. NCLM states that it appreciates DEP's plan to host an initial workshop, but notes that the Stipulation does not address when the Power/Forward grid investments and AMI technology will provide additional means for customers who actively manage their use of electricity to save on their power bills. NCLM recommends that the Commission require DEP not only to hold a technical workshop on its Power/Forward grid investments, but also to include customers and the Public Staff in a series of meetings about customer benefits of Power/Forward and AMI, and order DEP to develop proposals for the new and innovative time-of-use rate designs and prepayment options, and provide that information to customers as expeditiously as possible.

The Company agreed with the Public Staff in the Stipulation to maintain the current differential between on- and off- peak energy rates in all TOU rate schedules. (Stipulation IV.F.3.b.) The Commission hereby finds that maintaining the existing differentials among on-peak, shoulder, and off-peak energy rates is just and reasonable in light of the evidence provided. The Commission concludes that changing the differential between on-and off- peak rates should be deferred until significant rate design changes associated with the Company's AMI deployment are made.

SGS-TOU

Kroger witness Bieber testified regarding the Company's adjustments to rate schedule SGS-TOU. Witness Bieber asserts that the proposed SGS-TOU rate design understates demand charges while overstating energy charges relative to costs, which results in a greater misalignment of the costs and charges for the schedule. (Tr. Vol. 7, p. 224.) According to witness Bieber, the proposed rate design increases energy costs 17.19%, while only increasing demand costs 6.15%, resulting in customers with relatively higher load factors being required to subsidize the costs of the lower-load-factor customers within the rate class. (Id. at 225.) Accordingly, witness Bieber recommended that the Commission accept the Company's proposed BCC and recover the remainder of the revenue requirement increase for the SGS-TOU rate class through an increase in the demand charge component, while maintaining the current off-peak energy charge. (Id. at 228; Bieber Ex. 2.)

In his rebuttal testimony, witness Wheeler asserts that witness Bieber's SGS-TOU rate design should be rejected because it fails to properly consider marginal cost, has a disparate impact on customers served under the schedule, and encourages migration away from a TOU design thereby discouraging load shifting. (Tr. Vol. 10, p. 233.) The current SGS-TOU demand rates exceed marginal cost. (Id. at 231.) Therefore, significantly increasing these rates close to embedded unit cost is inappropriate. (Id.) Instead, DEP increased both demand and energy rates by the same percentage to better recognize both the rate class embedded unit cost and marginal cost. (Id.) Moreover, witness Wheeler explained that by increasing revenues under Schedule SGS-TOU by 10% more than the MGS Class under the proposed rates that the schedules will move toward rate parity for the two primary MGS class tariff options, without causing an economic hardship for SGS-TOU participants. (Id. at 233.) Additionally, witness Wheeler testified that little rate migration is anticipated under the Company's current rate design, but that witness Bieber's proposal changes the load factor where SGS-TOU would be beneficial from 30% to 36%, thereby encouraging customers to switch to Schedule MGS to realize a lower bill. (Id. at 232.) If witness Bieber's design is accepted, a migration adjustment would be required to give the Company an opportunity to realize its full revenue requirement. (Id.)

In its post-hearing Brief, Commercial Group contends that the various class cost of service studies (CCOSS) show that the Medium General Service (MGS) class provides above-average returns to DEP, as it did under the different CCOSS methods following the 2013 rate case (Tr. Vol. 11 p. 33), and, thus, the MGS class is subsidizing other ratepayer classes. DEP proposed to allocate any revenue increase to rate classes on the basis of rate base, and then adjust the increase each class receives in order to produce a 25% reduction in each class's variance from the overall average rate of return. (Tr. Vol. 7, p. 98 (Chriss/Rosa, citing Bateman Direct at 10.)) Commercial Group states that it does not take issue with this gradual approach to class revenue allocation, except if the

Commission grants the proposed JRR. In such event, the Commission should set LGS rates at cost in order to avoid a double subsidy by MGS customers. (Tr. Vol. 7, p.100 (Chriss/Rosa)) Otherwise, according to Commercial Group, MGS ratepayers would be forced to pay one subsidy to the LGS and other ratepayer classes and another subsidy to LGS industrial customers under the JRR, which would be both unjust and unreasonable. Commercial Group also notes that in the Stipulation and in its settlement with DEP the MGS class subsidy burden was recognized by providing that the SGS-TOU rate schedule (which falls within the MGS class) should receive the same overall revenue increase percentage as does the MGS rate schedule. Further, to ensure a more equitable impact for the MGS class, Commercial Group and DEP agreed that the revenue increase applicable under Schedules MGS and SGS-TOU should strive to achieve approximately the same percentage increase in revenues under each schedule. Commercial Group maintains that the Commission should adopt this reasonable resolution.

In its post-hearing Brief, Kroger notes that on November 27, 2017, Kroger and DEP agreed to a partial Settlement Agreement in which Kroger and DEP agreed that the revenue increase applicable under Schedules MGS and SGS-TOU should strive to achieve approximately the same percentage increase in revenues under each schedule, and that an identical provision is also contained in the Settlement Agreement signed by DEP and Commercial Group. Kroger states that witness Bieber explained that there is no evidence in the record to support a rate spread in which SGS-TOU receives a higher rate increase than the MGS class in general, and, therefore, the Settlement Agreement signed by Kroger and DEP will result in rates for MGS and SGS-TOU that are fair, just and reasonable.

Pursuant to the Stipulation, the Kroger Settlement, and the Commercial Group Settlement, the Stipulating Parties, Kroger, and the Commercial Group agreed to the Company's proposed SGS-TOU rate design, with the condition that "[t]o ensure a more equitable impact on the MGS class, the revenue increase applicable under Schedules MGS and SGS-TOU should strive to achieve approximately the same percentage increase in revenues under each schedule." (Stipulation IV.F.3.d.)

In light of the parties' testimony and the Kroger Settlement, which the Commission accepts in its entirety and upon which the Commission places great weight, the Commission finds and concludes that the Company's proposed SGS-TOU rate schedule, as modified by the Stipulation, is just and reasonable. The Commission finds that DEP's proposed SGS-TOU rate schedule recognizes marginal costs and will provide parity between the two primary MGS rate schedules. Accordingly, the Commission approves the Company's proposed SGS-TOU rate schedule, as agreed by Kroger.

LGS-TOU

Similar to witness Bieber's arguments related to SGS-TOU, CUCA witness O'Donnell and CIGFUR witness Phillips testified that the Company's proposed LGS-TOU demand rates should be increased to reduce the impact on higher load factor customers and better reflect the LGS class demand-related unit costs. (Tr. Vol. 15, p. 216; Tr. Vol.

17, pp. 67-70.) According to witness O'Donnell, customers with a higher usage per a given level of kW demand have rate increases of approximately 13%, while lower-usage customers have rate increases of approximately 11%. (Tr. Vol. 15, p. 216.) He instead recommends that the Commission approve a more gradual change in load factor variance among the LGS-TOU rate class because it will help higher load factor large manufacturers absorb this proposed rate increase and may, in some cases, be the difference in retaining jobs in the DEP service territory. (Id.) Witness Phillips specifically recommends that no increase be applied to the energy component and that the Company recover the revenue requirement increase for the SGS-TOU rate class through increases in the customer and demand charges. (Tr. Vol. 7, p. 70.)

Witness Wheeler explained that the Company's proposed LGS-TOU rate recovers the requested revenue requirement in a manner that is equitable to current customers, minimizes disparity in the percent impact on customer bills, and doesn't unduly incent customers to migrate to an alternative schedule to gain a lower bill. (Tr. Vol. 10, p. 234.) Witness Wheeler explained that witness O'Donnell's criticism of LGS-TOU ignores the fact that nearly all customers served under the schedule already have higher than average load factors. (Id. at 235.) He further explained that Wheeler Exhibit No. 3 includes lower load factor customers for illustrative purposes, but that such customers rarely receive service under Schedule LGS-TOU since Schedule LGS offers a lower bill. (Id.) Thus, if the lower load factor calculations are excluded, the increase on all LGS-TOU customers at a given demand is roughly the same. (Id.) Witness Wheeler also testified that witness Phillips' recommendation should be rejected because it fails to properly consider marginal cost, has a disparate impact on customers served under the schedule, and encourages migration away from a TOU design thereby discouraging load shifting. (Id. at 238.)

The Commission finds and concludes the Company's proposed LGS-TOU rate design is just and reasonable in light of the evidence presented. The Commission, therefore, rejects the recommendation of witness Phillips on the grounds that his proposal is unmerited given the fact that the increase for all LGS-TOU customers will be roughly the same, and that his proposal is likely to result in rate migration away from a TOU design that would result in discouraging load shifting.

Standby Service Rider

Commercial Group witnesses Chriss and Rosa argue that under the Standby Service (SS) Rider, the Standby Service Contract Demand should be set as the maximum increased demand the Company is requested to serve whenever the customer's generation is not operating, which may be less than the generator nameplate rating. (Tr. Vol. 7, p. 106.) For Rider SS customers with less than 60% planning capacity factor, the Contract Demand is the nameplate capacity of the self-generator. (Tr. Vol. 10, p. 238.) For greater than 60% planning capacity factor, the contract demand is the maximum increased demand of the SS customer when the generation is not operating. (Id. at 238-39.)

Witnesses Chriss and Rosa testify that the manner in which the Standby Service Contract Demand is determined under the SS Rider is inequitable because it allows one group of customer generators to determine their standby needs, which may be less than the nameplate capacity of the generator, and request that amount of service from the Company, while the other group of customer generators must pay for standby service for the nameplate capacity of their generator regardless of whether that service is actually needed. (Tr. Vol. 7, p. 105.) Witnesses Chriss and Rosa argue that this is unfair to customers who use solar and wind generation, and it creates a barrier to renewable energy opportunities. (Id.)

Witness Wheeler explained that renewable generation customers with planning capacity factors below 60% are different from those with planning capacity factors greater than 60% as they have little ability to influence the hours when their generation is operative and are totally dependent upon the availability of their energy resource. (Tr. Vol. 10, p. 239.) Unlike cogeneration and base load generation resources with capacity planning factors greater than 60%, when the under-60% renewable generation fails there is often little offsetting reduction in the participant's load requirements, and the load required of the utility instantly increases by the full output of the failed self-generator. (Id.) This will occur when there is an equipment failure or when the energy resource is disrupted. Because these customer generator's monthly operations and hourly demands are difficult to predict, DEP's facilities must be constructed assuming the customer's self-generation is unavailable. (Id.) Therefore, it is appropriate to charge customers with planning capacity factors below 60% a reservation charge based on the nameplate rating of their generation systems. (Id. at 240.) For example, if a cloud passes a solar generator customer's site, DEP generation must instantaneously be available to replace the customer's source. (Id.) Moreover, during night-time hours or when the customer's generation fails to operate, DEP generation must be available to replace 100% of the customer's generation. (Id.) Witnesses Chriss and Rosa are requesting that customers receive this back-up power service at a greatly reduced or no cost because their retail demand might not be reduced due to the coincidence of their load with their generation. (Id.) Witness Wheeler explains that contrary to Commercial Group's assertions, the generation reserve charges under the SS Rider should be set based on "availability" cost and not "usage" cost. (Id. at 241.) For customers operating generation with less than a 60% planning capacity factor, DEP must stand ready to instantly provide full replacement power whenever the self-generator is inoperative, which may or may not coincide with the customer's peak billing demand. (Id.)

Commercial Group states that witness Chriss demonstrated that a significant portion of the Generation Reservation Charge assessed to Rider SS customers with solar or wind generators would recover generation reservation capacity cost that the customers already pay for in their underlying tariff demand charges, and that this duplicative overcharge billing constitutes a significant barrier to on-site installation of solar or wind generation. (Tr. Vol. 7, pp. 102-05.) In addition, Commercial Group points out that recent legislation, N.C. Session Law 2017-192, would require DEP and other electric utilities to file new net metering rates that are set such that customer generators pay their full fixed cost of service. (Id. at 24.) In this context, DEP and Commercial Group reached the following agreement: DEP agrees that it shall work with interested commercial and industrial customers to investigate the issues concerning Rider SS that were raised in the direct testimony Commercial Group filed in the docket. (DEP/CG Settlement, Para. 3) Commercial Group urges the Commission to approve this agreement in order to give the parties more time to work on this complicated rate design issue.

The Company and Commercial Group settled this issue and all other issues between them, and agreed that DEP "shall work with interested commercial and industrial customers to investigate the issues concerning Rider SS that were raised in the direct testimony the Commercial Group filed in the Docket." (Id.)

In light of the parties' testimony and the Commercial Group Settlement, which the Commission accepts in its entirety and upon which the Commission places great weight, the Commission finds and concludes that the Company's proposal for maintaining the currently approved approach of setting the Standby Service Contract Demand under the SS Rider is just and reasonable to all parties and should therefore be continued. Because the Company must be ready at any time to instantly provide 100% of the energy needs of customers operating generation with less than a 60% planning capacity factor, it is appropriate to set a generation reserve charge based on the nameplate capacity of these customers' generators. Accordingly, the Commission approves the Company's proposed SS Rider, as agreed by Commercial Group.

Street Lighting

NCLM witness Saffo testified regarding a potential convergence of factors that will create a "perfect storm" that will dramatically and adversely affect municipal budgets in the near future. The factors cited by witness Saffo include: (1) continued rapid growth of cities as more people seeking jobs move to them from rural areas and from other parts of the country, (2) increased demands for infrastructure and municipal services for this growing population, and (3) the substantial increase in rates for electricity that DEP is requesting. As a result, witness Saffo encouraged the Commission to require DEP to deploy technological capabilities and new time-of-use rate designs as expeditiously as possible to incentivize customers to alter their energy usage so that they may more efficiently consume electricity by shifting consumption to off-peak hours. Further, he stated that based on the mutual benefits to municipal customers, public authority customers and to DEP from technological innovation, DEP and the municipal and authority customers should collaborate to facilitate such innovation.

Further, NCLM witness Saffo testified that the City of Wilmington has benefited from LED technology. However, he testified that despite the fact that LED street lighting systems are becoming more economically feasible, many municipalities cannot take advantage of the benefits of LED lighting due to the cost of converting to LED fixtures. (Pre-Filed Direct Testimony of Bill Saffo, p. 15.) Witness Saffo recommended that DEP provide financial incentives to municipalities to utilize LED lighting. (Id.)

DEP witness Wheeler, during cross-examination, noted that DEP had done quite a bit to help street lighting and bring the rates down to the extent DEP could within the context of a revenue requirement. For example, the area lighting and street lighting schedules were merged into a common lighting group as a way to minimize the impact on street lighting in this case. Further, witness Wheeler noted that the proposed increase is roughly half of what it would have been if the classes had not been merged.

Witness Wheeler explained that the Company collaborates with NCLM. He noted that the Company meets every six months with the municipalities to discuss their needs relative to lighting issues. When asked if there are any plans to implement some innovative LED lighting incentives or other ways of looking at rates in the future, witness Wheeler responded that the Company had made some changes since the last rate case. He stated that additional LED streetlights as well as LED floodlights were added. According to witness Wheeler, the Company is continuing to advance its portfolio of LED products. He stated, "The main thing I work with is pricing of those new products and features you're interested in. I've got to be able to offer you the product you want for the price you want. Right now, that's somewhat difficult with some technologies we have out there. But we are working to try to drive the prices down." (Tr. Vol. 10, p. 302.) Witness Wheeler noted that the Company hopes to offer additional products that would be of interest to the municipalities next year.

NCLM states in its Brief and partial proposed order that there are numerous public benefits associated with LED technology, including increased energy efficiency, lower maintenance costs, and improved lighting. Further, NCLM stated that many municipalities in North Carolina have begun to transition to LED technology in order to realize these public benefits. NCLM further noted that Commission Rule R8-47 (Requirements of Minimum Standard Offerings of Lighting Luminaries) explicitly recognizes these benefits and provides that "[u]tilities are urged to investigate new, more efficient lighting systems as they are developed and, where such systems are efficient and economical to the customer, request approval of newer systems as standard tariff items." NCLM requested that the Commission order DEP to provide greater incentives for LED street lighting conversions consistent with Commission Rule R8-47.

In addition, NCLM states that many municipalities are not able to take advantage of the benefits of LED lighting due to the cost of converting their own lighting to LED fixtures. NCLM states that municipalities could achieve large cost savings through LED lighting, and DEP should provide financial incentives to municipalities that utilize LED lighting. Thus, NCLM requests that the Commission order DEP to provide greater incentives for LED street lighting conversions consistent with Commission Rule R8-47.

Further, NCLM states that in DEP's proposed rates and the Stipulation, the proposed rate of return for the ALS and SLS customer class exceeds the rate of return for all other classes. (Settlement Support Testimony of Laura A. Bateman, Tr. Vol. 6, Updated Bateman Exhibit 2 – Partial Settlement, p. 1, Spread of Proposed Increases to Customer Classes.) NCLM notes that Public Staff witness Floyd testified that the Public Staff seeks to "maintain a +/- 10% 'band of reasonableness' for RORs, relative to the overall jurisdictional ROR such that to the extent possible, the class ROR stays within this band of reasonableness following assignment of the proposed revenue increase and move each customer class toward parity with the overall jurisdictional rate of return and avoid the potential for rate shock." (Tr. Vol. 19, p. 99.) While the overall rate of return in the partial settlement is 7.09%, the rate of return for the street lighting class in the proposed settlement is 13.92% (13.82% with the EDIT Rider). (Agreement and Stipulation of Partial Settlement, Docket No. E-2, Subs 1142, 1131, 1103, 1153, November 22, 2017, at p. 5)

NCLM states that street lighting is typically the greatest portion of a municipality's budget for electricity, and that municipalities and the municipal taxpayers should not suffer disproportionately in this rate case because DEP has proposed a disproportionately high rate of return for street lighting. The NCLM respectfully requests that the Commission order DEP to adjust its street lighting rates to bring the rate of return for this customer class into the band of reasonableness and move this customer class toward parity with the overall jurisdictional rate of return. The NCLM submits that the overall rate of return for the ALS, SLS customer class should be about 7.09%.

Based on the testimony of witness Wheeler, and specifically the Company's emphasis on LED lighting and continuing efforts to address the interests of the municipalities, the Commission is not persuaded that it should order DEP at this time to provide additional incentives for LED street lighting conversions, as requested by NCLM.

Summary with Respect to Rate Design

Based on the testimony of witness Wheeler, with consideration of the testimony of witnesses Wallach, Deberry, Barnes, Howat, Alvarez, Bieber, Phillips, O'Donnell, Chriss, Rosa, Saffo, and Floyd, as well as the Stipulation, the Commission finds and concludes that the rate design provisions in Section IV.F.3 of the Stipulation are just and reasonable to all parties in light of the all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 35-36

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

As fully discussed above, the provisions of the Stipulation are the product of the give-and-take of settlement negotiations between DEP and the Public Staff. Comparing the Stipulation to DEP's Application, and considering the direct testimony of the Public Staff's witnesses, the Commission notes that the Stipulation results in numerous downward adjustments to the costs sought to be recovered by DEP. Further, the Commission observes that there are provisions of the Stipulation that are more important to DEP, and, likewise, there are provisions that are more important to the Public Staff. For example, the Public Staff was intent on reducing the cost recovery for DEP's Zero Liquid Discharge project at the Mayo plant and for the Sutton combustion turbine project.

Further, the Public Staff was resistant to the substantial increase in the residential basic customer charge proposed by DEP. Likewise, DEP was intent on maintaining the depreciation rates set in its Depreciation Study. Nonetheless, working from different starting points and different perspectives, the Stipulating Parties were able to find common ground and achieve a balanced settlement.

In addition, the Commission notes that the Partial Settlement Agreement between DEP and NC Justice Center provides customer benefits that are beyond what the Commission has the authority to require of DEP. The Partial Settlement Agreement provides that DEP will contribute $2.5 million to the Helping Home Fund for low-income energy assistance.

The result is that the Stipulation strikes a fair balance between the interests of DEP 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 DEP's customers in receiving safe, adequate, and reliable electric service at the lowest reasonably possible rates, and the interests of DEP in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. Further, the Commission finds and concludes that the revenue requirement, rate design, and the rates that will result from the Stipulation, subject to the Commission's decisions set out below on the contested issues, will provide just and reasonable rates for DEP 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 three settlement agreements entered into by DEP with Commercial Group, Kroger, and NC Justice Center are in the public interest and should be approved in their entirety.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 37-43

The evidence supporting these findings of fact and conclusions is contained in the record of Docket No. E-2, Sub 1131, in the testimony of Company witness Bateman, and Public Staff witnesses Maness and Peedin, and the Stipulation.

In the Company's last rate case, Docket No. E-2, Sub 1023 (Sub 1023), the Commission approved $12.7 million as the reasonable annual storm costs included in rates. During 2016, DEP incurred extraordinary incremental expenses in connection with restoration and rebuilding efforts due to Hurricane Matthew and several other major storms. DEP estimated the total incremental costs charged to operation and maintenance (O&M) expense to repair and restore its system following the storms was approximately $80.2 million. In addition, the Company stated that it had incurred approximately $49.4 million in capital investments as part of its restoration efforts.

On December 16, 2016, in Docket No. E-2, Sub 1131, DEP filed a Petition for Accounting Order to Defer Incremental Storm Damage Expenses. In this petition the Company requested an accounting order to defer incremental storm costs incurred during 2016. In its petition, DEP requested that the Commission issue an Order allowing DEP to establish, net of the $12.7million[14] of storm cost expense already included in DEP's base rates, a regulatory asset and defer until its next rate case the incremental O&M storm expenses, the depreciation expense and carrying costs at DEP's weighted average cost of capital on the incremental capital cost, as well as the carrying costs on the deferred costs incurred in connection with these storms.

In its request, DEP discussed each of the storms, many of them named storms, that plagued its system in 2016. DEP provided such details as the number of customers affected, length of time service was interrupted, and staffing requirements by the Company. With the exception of the June and July thunderstorms, DEP characterized each of these storms as major, or significant. The June and July thunderstorms were stated by DEP to be unusual for the Carolinas. Further, DEP discussed its work alongside many city, county, and state government agencies during a number of these storms.

The Commission issued requests for comments in the Sub 1131 docket. In the Public Staff's initial comments, filed on March 15, 2017, it recommended:

1. That the Company only be allowed to defer storm expenses in excess of an amount of $27.4 million[15];

2. That no deferral of depreciation expense or return on undepreciated capital costs be allowed;

3. That no return on the deferred asset be allowed during the deferral period;

4. That DEP be required to start amortization of the deferred costs in

   October 2016; and

5. That the amortization period be extended from the three years proposed by

   the Company to 10 years.

In its reply comments, the Company contended that the limitations the Public Staff seeks to impose would deny the Company the ability to recover the costs incurred in

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[14] The $12.7 million figure was derived from an average of the Company's annual storm expenses over the 10-year period prior to DEP's last rate case in 2012. This is the amount of normalized storm costs allowed by the Commission in DEP's last general rate case in Docket No. E-2, Sub 1023.

[15] The $27.4 million figure is derived from an average of the Company's annual storm expenses over the 10-year period prior to the present rate case.

excess of the amount of storm-related expense found by the Commission to be normal in the Company's last general rate case. The Company noted that it had established (and the Public Staff did not disagree) that, absent an approval of its request, it is expected to earn below the return last authorized by the Commission. DEP argued that the limits imposed by the Public Staff would force the Company to face earnings degradation arising from these incremental storm costs, and these effects could impair the Company's financial stability and ability to attract capital on reasonable terms for the benefit of customers.

Additionally, in its reply comments, DEP suggests that the Commission authorize the Company to amortize the deferral over a shorter-time horizon and offered three years as a suggested period of time. DEP further stated in its comments that while the Company agrees with the Public Staff that the requested deferral is a large amount when compared to other storm deferrals, the deferral's overall effect on rates does not warrant a 10-year amortization period. DEP commented that despite the size of the recommended deferral, the increase in rates paid by customers is not so burdensome as to require an amortization period over the longest span of time used by the Commission.

In an Order issued on July 20, 2017, the Commission consolidated Sub 1131 with the current pending rate case proceeding. As noted in the Stipulation, the Stipulating Parties were unable to agree on the amount of the Company's requested deferred storm costs to be recovered and the amortization period of any such recovery.

DEP witness Bateman stated in her testimony that DEP had made a pro forma adjustment to normalize storm costs to an average level of costs that DEP has experienced over the last 10 years. She testified that the pro forma removed any storm costs from the 10-year average calculation that were included in the Company's 2016 storm deferral request and instead includes an amortization of the deferred costs over a three-year period.

Company witness Bateman testified that DEP's 2016 storm costs amounted to $80 million of incremental operating expense and $49 million of capital expenditures, on a North Carolina retail basis. (Tr. Vol. 6, pp. 124-25, 203-04.) She stated that the Company proposed to recover all of the incremental operating expenses (except for the $12.7 million that had already been included in rates), depreciation and return on the capital expenditures, and a return on the deferred costs, through amortization over a three-year period. (Id.)

On cross-examination, witness Bateman acknowledged that the Commission has never approved, nor had the Company ever before requested, deferral of capital costs resulting from a storm, or a return on the unamortized balance of deferred storm costs. (Tr. Vol. 7, pp. 447-48.) She also acknowledged that many of the ratepayers who are being asked to reimburse the Company for its storm costs have themselves suffered severe losses in Hurricane Matthew and other storms. (Tr. Vol. 7, p. 452.)

Public Staff witness Maness testified that a utility should not be entitled to defer and amortize all its storm costs above the average figure approved in its previous general rate case. (Tr. Vol. 18, pp. 321-22.) Recovery of storm costs after the fact, through deferral and amortization, should be limited to costs that are extraordinary. Witness Maness noted that storm costs naturally fluctuate from year to year, and the costs incurred in a given year should not be considered extraordinary unless they are outside the normal range of variation. In this case, he pointed out, the evidence showed that over the period from 2002 to 2015, DEP's storm costs had varied "from one annual amount as low as $1.8 million to one as high as $27.2 million." Moreover, during five different years within this fourteen-year period, DEP had incurred storm costs ranging between $22.9 million and $27.4 million. Consequently, witness Maness testified that the normal range of storm cost variation in DEP's service area extends at least as high as $27.4 million, and only costs in excess of this level should be considered extraordinary and eligible for deferral.

Witness Maness further testified that "[h]istorically, the Commission has amortized storm damage expenses over spans of time ranging from 40 months to ten years." (Tr. Vol. 18, p. 322.) Because the Company's storm losses in this case were so unusually large, he contended, the Commission should consider an amortization period at the longest end of the range – that is, a 10-year period.

In addition, witness Maness noted that in cases involving single-storm deferrals, the Commission has generally begun the amortization period in the month when the storm occurred. (Tr. Vol. 18, p. 322.) In this case DEP's deferral request includes numerous storms, but the majority of the costs were incurred during the latter part of the year. In particular, Hurricane Matthew, by far the most costly and damaging of the 2016 storms, occurred in October. Because of this, witness Maness recommended the amortization period for the deferral should begin in October 2016. Finally, he noted that although operating and maintenance costs resulting from major storms have often been deferred, there appears to be no precedent supporting deferral of the depreciation expense and associated carrying costs resulting from storm damage.

As shown in Public Staff Peedin's Revised Exhibit No. 2-1(b), Line 3, witness Peedin calculated a total deferral amount of $52,752,000 for 2016 storm costs, with an amortization period of ten years beginning in October 2016, using the procedure recommended by witness Maness.

Witness Peedin further testified that the amount of North Carolina retail normalized annual level of storm costs to be included in the Company's rates is $11.018 million. The calculation is provided on Peedin Revised Exhibit No. 3-1(o). In her testimony, she stated that she adjusted the Company's level of storm expenses (which had been included as a pro forma adjustment) by reflecting a normalized level of storm expense based on the average annual storm expense (excluding base labor costs) incurred by DEP over a ten-year period, adjusted for inflation. (Tr. Vol. 18, pp. 77-78.)

The Commission agrees with the Public Staff that DEP is seeking to defer and amortize a larger proportion of its storm costs than the Commission has historically allowed. The Commission's precedents do not require that ratepayers bear the entire cost of repairing the damage to a utility's system resulting from a major storm. Instead, deferrals of storm costs are limited to those costs that are beyond the normal range of fluctuation of storm costs from year (in this case, costs in excess of $27.4 million). In recent general rate cases, the Commission has also included in the utility's rates a storm cost allowance based on the <u>average</u> amount the company has incurred over a period of years (the storm cost allowance approved in Sub 1023 was $12.7 million per year). Costs may exceed an average, or normal, amount used to set rates in a general rate case; however, as long as those excess costs are within a normal range of variation, they should be presumed to be recovered through the utility's rates in effect at that time (given the fact that many expenses fluctuate from year to year).

The Commission is concerned about the asymmetry of risk that would exist if the Company were allowed to defer all costs in excess of the $12.7 million used to set storm expenses in the most recent general rate case. Evidence presented in this case showed that in several recent years there were few major storms, and the Company's total storm costs were below $12.7 million; however, ratepayers received no credit for the difference between actual costs and the $12.7 million. In contrast, in those years when extremely severe storms such as Hurricane Matthew occur, there is no upper limit to the costs that may be placed upon ratepayers.

The Commission is concerned that the Company's proposed treatment of storm costs in this case may set a dangerous precedent for other categories of costs in the future. Witness Bateman testified that the $12.7 million of storm costs included in the Company's last general rate case should be considered ordinary, and all storm costs in excess of this amount should be considered extraordinary and recovered on a deferred basis. (Tr. Vol. 7, pp. 427-28.) Under this approach, the Company would be assured of recovery of all its storm costs on almost a "true-up" basis, either through the presumed annual allowance in rates or through deferral and amortization. In effect, DEP's proposal would amount to a "tracker" system for storm cost recovery, similar to the riders established by the General Assembly in G.S. 62-133.2, 62-133.8 and 62-133.9 for fuel, REPS, and DSM/EE cost recovery. If DEP is allowed to implement such a system for recovery of its storm costs, other utilities may well seek to adopt a similar approach for any of various other expense items. In light of this concern, and the attendant shifting of more risk to customers, the Commission has generally been reluctant to approve cost tracker systems, except when they are required by statute.

The Commission is further concerned that a dangerous precedent would also be set should it allow all of the storms DEP requested in the deferral – namely the June and July thunderstorms. DEP stated in its request that these thunderstorms that occurred in June and July were "unusual." The Commission determines that these thunderstorms do not rise to the level to receive deferral treatment by the Commission. The Commission concludes that it is not at all uncommon, or unusual, in the Carolinas to have thunderstorms, sometimes severe. For these reasons, DEP's request to include $1.720 million in O&M expenses related to the June and July 2016 thunderstorms is hereby denied.

For all these reasons, the Commission finds and concludes that approval of the full amount of the Company's proposed storm cost deferral would be unjustified. The appropriate amount to be allowed deferral treatment is $51.032 million, which is the Company's requested amount of $80.152 million, minus the June and July thunderstorm disallowance of $1.720, minus the $24.7 million normal storm range expense. With regard to the amortization period, however, the Commission agrees with DEP that the deferral in question does not warrant amortization over the longest period of time, 10 years, which has historically been utilized by the Commission. The Commission, however, believes that the deferral warrants more than a three-year amortization period as suggested by DEP. The Commission takes judicial notice that the amortization of five years (60 months) has been the prevailing amortization period for storm deferrals. Hurricane Isabel storm costs were authorized to be amortized over five years in Docket No. E-2, Sub 843, and Hurricane Hugo storm costs were amortized over a five year period in Docket No. E-7, Sub 460. The Commission takes particular note of the Hurricane Hugo deferral, as this deferral was quite large at $62.4 million. Therefore, the Commission finds and concludes that there is good cause to require that DEP amortize the deferred storm damages O&M expenses over a five-year period. Further, the Commission concludes that since the most severe storm affecting the Company's service area in 2016 by far was Hurricane Matthew, which occurred in October, the amortization period should commence in October 2016. This follows the Commission's historic precedent of beginning amortization at the time when the costs, or bulk of the costs, are incurred. Further, the Commission concludes that if DEP continues to recover the deferred costs for a longer period of time than the amortization period approved by the Commission that does not mean that DEP is then entitled to convert those deferred costs into deferred revenue. Rather, the Company should continue to record all amounts recovered as deferred costs in the specific regulatory asset account established for those deferred costs until the Company's next general rate case.

Regarding the capital costs, the Commission views storm capital costs as significantly different from incremental O&M storm costs. Unlike the incremental O&M costs, DEP's capital costs will become a part of DEP's rate base, and will become a part of DEP's future depreciation expenses. Based on these factors, and recognizing that cost deferral is an exception to the traditional ratemaking principles applied by the Commission, the Commission finds and concludes that there is not good cause to allow DEP to defer the incremental capital costs of Hurricane Matthew. Therefore, the Commission believes that it is appropriate and reasonable to continue its historical practice of not allowing deferral and amortization of capital costs or carrying costs on the deferral. Finally, the Commission finds and concludes that the appropriate North Carolina retail normalized annual level of storm costs to be included in the DEP's rates in this case is $11.018 million, as the Commission finds it to be just and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 44-49

The evidence supporting these findings of fact and conclusions is found in DEP's verified Application, DEP's Petition for an Order Approving a Job Retention Rider (JRR), filed on August 14, 2017, in Docket No. E-2, Sub 1153 (Petition), the testimony of

Company witness Wheeler, the testimony of Public Staff witness McLawhorn, the testimony of other witnesses, the exhibits of witness Wheeler, and the entire record in this proceeding. The Commission takes judicial notice of the Company's Initial and Reply Comments filed in Docket No. E-100, Sub 73 where the Company outlined the conditions that led to the loss of industrial jobs and where the Commission issued establishing guidelines on December 8, 2015. (JRT Order)

In its Petition, DEP requests approval of its JRR, a five-year pilot program for industrial customers that is designed to curtail further loss of industrial jobs in DEP's service territory. (Petition, at 1.)

Company witness Fountain testified that "[t]he Company's proposed JRR is designed to stem further loss of industry, industrial production and industrial jobs in DEP's service territory, which the Commission acknowledged as an important policy goal for North Carolina when it adopted the Guidelines for JRRs." (Tr. Vol. 6, p. 83.) DEP witness Fountain stated the goal of retaining industrial jobs in the state is important to not only the customers of the state, but to DEP. (Tr. Vol. 6, p. 19) Company witness Wheeler provided more detailed testimony in support of the Company's proposed JRR. Witness Wheeler 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. 10, p. 250.) Since 2014, 53 manufacturing facilities served by Duke Energy have ceased operation in North Carolina. (See Wheeler Rebuttal Ex. No. 2.) Witness Wheeler stated that the Company's Integrated Resource Plan Update, filed on September 1, 2017, in Docket No. E-100, Sub 147, demonstrates the continuing struggles of manufacturing in North Carolina. (Tr. Vol. 10, p. 245.) He testified 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 Wheeler also explained the eligibility requirements for the proposed JRR. In order to be eligible for the proposed JRR, the customer must do all of the following: (1) use electric power as a principal motive power for the manufacture of a finished product, the extraction, fabrication or processing of a raw material, or the transportation or preservation of a raw material or a finished product; (2) perform an energy audit within six months, or verify an energy audit has been performed within the past 36 months; (3) verify the customer is considering the ability to shift production from its facility, is considering a need to reduce employment at its facility due in part to the cost of electricity, intends to reduce production due in part to the impact of the cost of electricity, or the customer's load is otherwise at risk. (Id. at 245–46.) Furthermore, in order to qualify for JRR, industrial customers must show that they (i) have or are considering the ability to shift production from their facilities to facilities in other states or countries; (ii) are considering a need to reduce the employment level at their facilities due in whole or in part to the impact of electricity cost; (iii) intend to reduce or are presently evaluating reduction of production levels or load due in whole or in part to the impact of electricity cost; or (iv) have load that is otherwise at risk of loss. (Petition at 5.) 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. (Id. at 246.)

In its Petition, the Company did not seek recovery of the revenue reduction resulting from implementation of the JRR at this time, but instead requested deferral accounting with interest on the amount in excess of the $3.5 million that the Company will absorb on a one-time basis. (Petition, at 3.) The Company stated the annual revenue impact of the JRR would be $24.8 million.

CUCA witness O'Donnell testified in support of the Company's proposed JRR. Witness O'Donnell testified that if DEP continues to lose industrial load, the fixed costs of operating the DEP system will be shifted to the remaining customers in an amount even greater than the average 0.74% cited in DEP's Petition. (Tr. Vol. 15, pp. 142–43.) For example, witness O'Donnell calculated that residential rates would increase by 13.03% (including the current requested rate increase and proposed GRIM rate increases) if the Company's manufacturing load completely eroded. (Id. at 143.) He concluded that it would be much less harmful to residential customers to pay a 0.67% increase for five years than to have a permanent 13.03% increase. (Id.) At the hearing, witness O'Donnell testified that the JRR "is an incentive to hopefully help manufacturers to continue to be competitive in North Carolina because the alternative is a lot worse." (Id. at 242.) He continued, "And since the last rate case we had here for DEP, DAK Americas did close their Navassa plant; 600 jobs gone right there. And that was a big load for DEP. That loss of load has to be absorbed by every other customer. That's what we're trying to avoid." (Id. at 242–43.)

CIGFUR 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, that the proposed JRR is in the public interest, and recommended that the Commission approve it. (Tr. Vol. 7, p. 74.) In CIGFUR's Post-Hearing Brief, CIGFUR proposed one adjustment to the proposed JRR to exempt rider participants from funding cost recovery. (Br. pp. 4-5)

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. 18, p. 29.) He argues 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 34.) 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 36.)

Additionally, witness McLawhorn expressed concern with the inclusion of customers involved in the "transportation or preservation of a raw material of a finished product." (Id. at 31.) The Public Staff understood this phrase to refer to pipelines including natural gas pipelines. Witness McLawhorn noted that gas pipelines are different from other manufacturing facilities in that pipelines are fixed investments that are not easily relocated, and unlike other industrial manufacturers, pipelines do not produce a finished product. He recommended this disputed phrase be eliminated from the eligibility criteria of the JRR.

Lastly, Public Staff witness McLawhorn testified that not only customers, but shareholders, benefit from the retention of industrial jobs and the load associated with the jobs. Therefore, a fair sharing of the revenue impact of the JRR would require the Company to contribute $3.5 million on an annual rather than one-time basis. In response to Commissioner Clodfelter's question, Public Staff witness McLawhorn stated the Public Staff did not calculate its proposed annual shareholder contribution amount of $3.5 million, but rather used the amount proposed by the Company on a one-time basis. (Tr. Vol. 18, p. 121.) Witness McLawhorn also testified that the Commission has the authority to set the amount recovered in the JRR, and can set the recovery at an amount composed of the revenue impact less the $3.5 million shareholder contribution. (Tr. Vol. 18, p. 125.)

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." (Tr. Vol. 18, p. 30.) Witness McLawhorn also testified that the proposed JRR is not unduly discriminatory because it is designed to reach the largest industrial customers, who impact other commercial and residential customer classes. (Id. at 29.) He further states 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.) Lastly, he recommended that the impact of the rate discount be recovered from all ratepayers, including the customers eligible for the rate discount.

Commercial Group witnesses Chriss and Rosa testified in opposition to the DEP'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. 7, p. 108.) They 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. at 109.)

In its post-hearing Brief, Commercial Group notes that after DEP and the Public Staff entered into a Stipulation, Commercial Group negotiated and reached a settlement with DEP that resolved additional issues, but left outstanding and unresolved the Commercial Group's concerns regarding the JRR. Commercial Group submits that the JRR would violate G.S. 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 G.S. 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 MGS and LGS classes, and that many non-industrial ratepayers in these classes have an aggregate load of at least 3 MW. (Tr. Vol. 7, p. 108.) 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 in the last two DEC rate cases, and the proposed Industrial Economic Recovery rider 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 DEP selected provide only an illusion of being reasonable criteria for determining which customers should receive a rate subsidy. As an example, Commercial Group contends that the applicant could simply state that it has at some time in the past thought about obtaining the ability to move a portion of its operations out of state, but the applicant need not presently have such ability, presently plan to move operations out of state, nor be in such financial condition that jobs would be lost but for a JRR subsidy. Commercial Group further notes that the applicant does not need to maintain existing levels of employment, but instead chooses a level of employment that it states it will maintain, even if the level is lower than its present level. Moreover, Commercial Group submits that the JRR eligibility criteria are so broad that they include gas pipelines, even though DEP states that it has no current pipeline customers. (Tr., Vol. 11, at p. 33)

Commercial Group notes that DEP witness Hevert gave convincing testimony that economic conditions in North Carolina have improved substantially since DEP's last rate case in 2013, and since the Commission adopted job retention guidelines in 2015. The unemployment rate in North Carolina and DEP's service territory has fallen substantially during these periods. (Tr. Vol. 8, pp. 123-32.) Further, the correlation between the drop in unemployment in North Carolina and more broadly across the United States has been very high. (Id. at 64) Moreover, DEP industrial customers already receive competitive rates that are below the national average and below the average in the Atlantic South region. (Wheeler, Tr. Vol. 11, p. 42) In addition, according to Commercial Group, the CCOSS DEP offered shows that LGS industrial customers already receive a 3% discount from not currently paying the full cost DEP incurs to serve those customers. (Tr. Vol. 7, p. 99; and Exh. CR-5, row 5)

Commercial Group also 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 DEP 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 recommends that the Commission require DEP to bear 50% of the JRR costs, with any remaining cost to be recovered from ratepayers on a percentage of bill basis.

Finally, Commercial Group contends that there is a third subsidy paid by high load factor MGS ratepayers because JRR costs would be imposed on a per-kwh basis instead of on a percentage of bill basis. Commercial Group states that this pancaking of subsidies one upon the other is patently unfair, and that the only rationale DEP provided for billing JRR cost on a per-kwh basis is that it seems to be easier for DEP to charge it that way. (Tr. Vol. 11, at 47:8-12).

DoD/FEA witness Mancinelli also testified in opposition to the Company's proposed JRR. Witness Mancinelli states that a subsidy is not necessary for industrial customers in North Carolina because the North Carolina economy is improving and DEP's industrial load is projected to increase without JRR. (Tr. Vol. 17, p. 153.) Similar to witnesses Chriss and Rosa, he states, however, that if the JRR is approved that it should be expanded to include major employers such as the DoD/FEA. (Id. at 155.) In its post-hearing Brief, in addition to reiterating the above-stated arguments, the DoD/FEA argues that if the JRR is adopted as proposed, in years beyond the first year with DEP's $3.5million contribution, the JRR will cost Fort Bragg and Camp Lejeune approximately $900,000 per year. (Br p. 2) The DoD/FEA further states that there are non-discriminatory methods to provide rate relief to the LGS industrial customers such as recognizing DEP as a winter peaking utility and using a winter 1CP cost of service model. (Br. Pp. 6-7)

Company witness Wheeler's rebuttal testimony responded to the concerns raised by other witnesses related the Company's proposed JRR. Witness Wheeler agreed with the Public Staff's concern regarding difficulty evaluating customer financial and employment records. (Tr. Vol. 10, p. 247.) To address this concern, witness Wheeler explained that DEP will impose a requirement that an officer of the customer sign the application. (Id.) Witness Wheeler also noted that the guidelines do not require a demonstration of financial distress, but the discounted revenue must contribute to job retention in North Carolina. (Id. at 247-48.) When questioned about this issue on cross- examination by counsel for Commercial Group, witness Wheeler stated that a customer applying for the JRR, "has to attest in the application that he has a competitive threat that would reduce employment in North Carolina, and the rider will help retain those jobs in North Carolina. If [the customer] doesn't retain the employment level he agrees to, the rider is removed from those accounts." (Tr. Vol. 11, pp. 38-39.) Moreover, Public Staff witness McLawhorn testified at the hearing that the verification process for the JRR is similar to the verification process for an industrial customer to opt-out of a utility's DSM/EE rates, which was incorporated in law by Senate Bill 3. (Tr. Vol. 18, p. 119.)

Witness Wheeler further testified that deferral accounting was requested because the timing and magnitude of the revenue reduction is unclear. (Tr. Vol. 10, p. 249.) "The use of deferral accounting allows the Company to assess the true impact of the rider and seek recovery at a later date when revenues are more certain." (Id.) Witness Wheeler also explained that the Public Staff's recommendation that the Company's shareholders absorb $3.5 million not only once, but in every year of the JRR should be rejected because it would deprive the Company of a reasonable opportunity to recover its just and reasonable costs. (Id. at 250.)

Additionally, witness Wheeler testified regarding the inclusion of customers involved in the "transportation or preservation of a raw material of a finished product," explaining that this language was included to allow the JRR to apply primarily to gas pipeline customers. (Id. at 247.) He stated that pipeline customers have expressed concerns with electricity costs and have requested rate relief to aid in their North Carolina operations. (Id.) DEP believes that it is reasonable to include this type of customer with manufacturing facilities when applying the JRR. (Id.) When questioned by counsel for NC Justice Center regarding whether an interstate gas pipeline could pick up and move to another state, witness Wheeler replied that "I don't believe [it] could pick up and relocate. It could cease to operate. It could reduce the amount of gas flowing into the state." (Tr. Vol. 11, p. 70.) Witness Wheeler also clarified that DEP had not designed its proposed JRR so that its Atlantic Coast Pipeline would qualify, stating that the guidelines in Docket E-100, Sub 73 were approved well before "the Atlantic Coast Pipeline [was] even . . . a consideration." (Tr. Vol. 11, p. 141.) In response to a question from the Chairman, he noted that DEP does not currently have any pipeline customers that would meet the proposed definition eligible under the JRR.

Lastly, witness Wheeler responded to the other witnesses' testimony that JRR should be expanded to customer classes other than just industrials. Witness Wheeler testified that sales to the industrial class in North Carolina have continued to be "flat to declining." (Tr. Vol. 10, p. 244; Wheeler Rebuttal Ex. 1.) In contrast, during this same period, sales to the commercial and public authority/military customer classes have continued to show growth. (Tr. Vol. 10, p. 252; Wheeler Rebuttal Ex. 1.) Therefore, witness Wheeler testified that DEP does not believe that it would be appropriate to expand JRR to other customer groups at this time. (Tr. Vol. 10, p. 252.) Witness Wheeler explained that the "JRR will assist in retaining jobs in industrial businesses in North Carolina and will help to minimize the transfer of cost from the industrial class to other rate classes due to plant closures." (Id. at 253.)

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 $3.5 million shareholder contribution." (Stipulation p. 4 - Paragraph II(c).)

Except for the two unresolved issues stated above, the Stipulating Parties have agreed to the proposed JRR as described by witness Wheeler 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.

(Stipulation p. 15.) 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 December fuel adjustment to match anticipated recovery revenues and true-up any past over-or under-recovery. (Stipulation pp. 15-16.) Additionally, due to the uncertain date of implementation, compliance tariffs shall be filed prior to implementation of the JRR Recovery Rider and customers shall be notified by bill insert or message upon implementation. (Id. at 16.)

Company witness Wheeler 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 $0.00051 per kWh to recover the first year of impact, less the $3.5 million absorbed by the Company, reduced by 10% for application lag. (Tr. Vol. 10, p. 258.) Witness Wheeler further testified that JRRR is intended to keep the Company revenue neutral with respect to the JRR, other than the one-time $3.5 million contribution from shareholders, over the 5-year pilot period, and, if needed, a final true-up shall be applicable upon termination of JRR. (Id.)

Commercial Group, in its post-hearing Brief, submits that the JRR would violate G.S. 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 SIC code distinctions that the Commission found discriminatory and rejected in prior proceedings.

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 DEP's service area would 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 many, if not all, concerns expressed by the Commercial Group and the Department of Defense 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 DEP 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. DEP shall change the application language accordingly. The Commission has considered the arguments for expanding the JRR made by DoD/FEA witness Mancinelli and Commercial Group witnesses Chriss and Rosa, and concludes that expanding the JRR to other customer classes would place too large a burden on non-participants and would be unreasonable.

Furthermore, the Commission concludes that limiting the availability of the JRR to only industrial customers is not unreasonably discriminatory. Rather, it is based on a reasonable difference between customer classes, and the discount offered to participants under the JRR as compared to the amount of rider recovery on non-participants bears a reasonable proportion to the difference between the customer classes. See State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, 348 N.C. 452, 468, 500 S.E.2d 693, 704 (1998). Based on the evidence presented, the Commission finds that industrial customers' sales have been flat or declining since the recession, while residential and commercial sales are growing. Furthermore, a $0.00323 per kWh reduction in rates for participating industrials as compared to an increase in rates for the average retail customer of approximately $0.00051 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 DEP'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. Further, due to the fact that DEP indicated that no pipeline customer is currently eligible for the JRR and that the Commission is limiting the JRR to one year with a possible extension of one year, it is unlikely that any pipeline customer would be affected by this decision.

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 set LGS rates at cost in order to avoid a double subsidy by MGS customers. 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 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 DEP to implement JRR and JRRR as proposed in the Stipulation and Wheeler 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 $3.5 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." (See 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. 50-52

The evidence supporting these findings of fact and conclusions is contained in the Application, Form E-1, the record in Docket No. E-2, Sub 1103, the testimony and exhibits of DEP witness Bateman, and Public Staff witness Maness.

In Docket No. E-2, Sub 1103, DEP 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 the amount of approximately $2.5 billion to reflect its estimated costs of CAMA compliance.

Company witness Bateman testified that based on estimated closure costs included in the 2012 dismantlement studies prepared for the Company by Burns & McDonnell, a third-party engineering firm, DEP is currently collecting costs associated with the closure of CCR basins in the cost of removal portion of its depreciation rates. However, those cost estimates were prepared prior to the enactment of CAMA, and were based on the industry standards and best practices recommended by the engineering consultants at the time. Witness Bateman testified that since that time CAMA has significantly increased the estimated closure costs for the Company's CCR basins, and changed the required accounting treatment, triggering asset retirement obligation accounting.

In its March 15, 2017 comments in Docket No. E-2, Sub 1103, the Public Staff supported the deferral request, provided that ratemaking treatment for the deferred amount would be determined in the next base rate case:

> In this particular case, the Public Staff believes that the non-capital costs and depreciation expense related to compliance with state and federal requirements cited in the Companies' petition generally satisfy the criteria for deferral for regulatory accounting (but not necessarily ratemaking) purposes. First, they are adequately extraordinary in both type of expenditure and in magnitude to justify consideration for deferral. Second, the effect of not deferring the expenses on the Companies' respective earned returns on common equity would be significant.

Initial Comments of the Public Staff, at p. 6.

Comments were also filed by CUCA, the AGO, Appalachian State University, the Cities of Concord and Kings Mountain, and Sierra Club.

In the present docket, Public Staff witness Maness testified that based on the magnitude and unique nature of the CCR costs, as well as other reasons stated in the Public Staff's comments filed in Docket No. E-2, Sub 1103, the Public Staff continues to believe that prudently incurred CCR expenditures should be allowed to be deferred for regulatory accounting purposes.

In its post-hearing Brief, the AGO contends that DEP's request to recover its deferred CCR costs involves single-issue ratemaking because DEP seeks to recover coal ash costs going back to the beginning of 2015, without a review of the other rate elements that were in effect that might offset the need for the cost recovery. Citing State ex rel. Utilities Commission v. Edmisten, 291 N.C. 451, 470, 232 S.E.2d 184, 195 (1977), the AGO contends that the North Carolina Supreme Court has long recognized the inequities of single-issue ratemaking: "Such rate making throws the burden of such past expense upon different customers who use the service for different purposes than did the customers for whose service the expense was incurred." Moreover, the AGO asserts that utility rates are established under statutory authority to recover the utility's cost of service and reflect a fair return, and the rates are presumed to be sufficient for the utility to recover all costs of serving its customers, and that a utility does not have a vested right to collect its unanticipated expenses, and that to "cast upon subsequent users the expense of serving prior users is discrimination forbidden by G.S. 62-140." Id., 291 N.C. at 470-71, 232 S.E.2d at 196.

Further, the AGO maintains that the Commission's discretion to defer costs for later recovery should be prospective from the time of the request, or at least close in time to the deferral request, not retroactive back two or three years, as DEP seeks in this case. The AGO contends that Commission Rule R7-27(a)(2)c [sic Rule R8-27(a)(2)c] requires electric utilities to apply to the Commission in order to use deferral accounting, and that, similarly, FERC Account 182.3, referenced in Rule R7-27(a)(2)c, provides for deferral accounting by the creation of a regulatory asset based on the ratemaking action of a regulatory agency, not based on unilateral action taken by the utility. In addition, the AGO contends that DEP failed to request authorization to defer the coal ash costs before they were incurred – delaying the filing of its petition for deferral until December 30, 2016, while seeking deferral of costs incurred back two years to January 1, 2015, so that they would be recoverable in a rate case expected to be filed in 2017. See Duke Energy Progress, LLC and Duke Energy Carolinas, LLC Petition for An Accounting Order, In the Matter of Joint Petition of DEP Energy Progress, LLC and DEP Energy Carolinas, LLC for an Accounting Order to Defer Environmental Compliance Costs, filed December 30, 2016, in Docket Nos. E-2, Sub 1103, and E-7, Sub 1110 (Petition to Defer Coal Ash Costs)

The AGO cites the Commission's Order Granting Motion for Reconsideration and Allowing Deferral of Costs issued August 12, 2003 in Docket No. E-2 Sub 826 (2003 ARO Order), and states that the Commission authorized DEP's predecessor, CP&L, to place certain ARO costs in a deferred account, but gave the following cautionary instruction relating to the creation of and accounting for new AROs:

> the Commission is of the opinion, and so concludes, that the Company should be, and hereby is, explicitly placed on notice that any proposed changes in the cost of removal for long-lived assets and/or in the accounting for such costs must be submitted to the Commission for its approval in the

> context of a general rate case or other appropriate proceeding prior to implementation.

2003 ARO Order, at 11-12.

Thus, according to the AGO, the Commission has directed that prior approval should be obtained in a general rate case for deferred accounting authorization under the circumstances presented in this case, and that DEP's unilateral decision to change how it accounts for CCR costs violated Commission rules and specific directions expressed in prior orders concerning AROs.

Having reviewed the comments filed in Docket No. E-2, Sub 1103, and the evidence regarding the ratemaking treatment for coal ash costs in the present rate case, the Commission determines that the deferral request is reasonable and appropriate. Company witness Bateman indicated that CAMA increased the estimated closure costs for the CCR basins which triggered asset retirement obligation accounting as stated elsewhere in more detail in this Order. As noted by Public Staff witness Maness, the costs for which DEP sought deferral meet the Commission's criteria for deferral for regulatory accounting purposes. Witness Maness further testified that the unique nature of the costs and the complexity of the issues justified a limited delay in determining the beginning date of any amortization of deferred expenses. Approval of deferral accounting does not prevent any party from taking issue with the merits or mechanisms for recovery of the deferred costs in the present rate case.

Among several cost of service adjustments recommended by witness Maness was the calculation of a return on deferred coal ash expenditures between January 1, 2015, and January 31, 2018, using a mid-month cash flow convention, rather than the beginning-of-month convention used by the Company. Witness Maness testified that the Company had used a return calculation methodology that accrued a return for each month assuming that all cash flows during the month occurred at the very beginning of the month. Because he felt this assumption to be unrealistic, he made an adjustment to instead use a mid-month cash flow assumption, which essentially treats the cash flows in each month as being experienced throughout the month. (Tr. Vol. 18, p. 308)

Additionally, witness Maness added a return on deferred coal ash expenditures from September 2017 through January 2018, to bring the total balance up to the expected effective date of the rates approved in this proceeding. He testified that the Company had updated its proposed balance of deferred coal ash management costs, with an accrued return, through August 2017. The return would be the Company's net of tax rate of return, net of associated accumulated deferred income taxes. However, the rates in this proceeding are not expected to go into effect until February 1, 2018. Therefore, in order to capture all of the costs, including return, related to the January 2015 - August 2017 underlying coal ash costs, he added the return accumulated on the principal amount through January 2018. (Tr. Vol. 18, p. 307)

Several intervenors made the same contention that the AGO made in its post-hearing Brief that the Commission should not approve a return on DEP's deferred CCR costs. One basis cited by the AGO for denying a return is the AGO's contention that DEP's CCR expenditures do not result in used and useful utility plant. The Commission fully addresses the issue later in this Order, and concludes that DEP's CCR expenditures do result in property that is used and useful.

The AGO argues that DEP's request to recover the deferred coal ash costs going back to the beginning of 2015 involves single-issue ratemaking because the costs are being reviewed without review of other rate elements that were in effect that might offset the need for cost recovery. The AGO further argues that DEP's request for recovery of "coal ash costs from the past two and a half years seeks impermissible prospective ratemaking (also called retroactive ratemaking in some cases)." (AGO Br. p. 41) The Commission finds that the AGO's arguments are misplaced. The Company requested deferral accounting and specifically requested the Commission determine the costs within a rate case to avoid the issues of single-issue ratemaking and retroactive ratemaking. Single-issue ratemaking is not an issue in the present case because the costs are not being determined outside of a rate case, but rather are being determined in a rate case, a proceeding in which other rate elements are reviewed. As for the retroactive ratemaking argument, the Public Staff has determined that deferral is appropriate in the present case and the Commission agrees. A cost deferral is a recognized practice that allows recovery of expenditures that might otherwise constitute impermissible retroactive ratemaking. The AGO cites to a 2003 Commission Order to support its contention that DEP should have received prior approval in a rate case; however, the language cited states a general rate case or "other appropriate proceeding," such as a request for deferral. The Commission agrees with the Public Staff that DEP properly made the deferral request, which the Commission consolidated into the general rate case. The AGO argues that DEP began incurring costs in early 2015 and that the Commission should deny the deferral because DEP should have requested the deferral earlier. The Commission is not persuaded. The Commission does not find that the timing of the request for deferral warrants denial of the request. See Order Granting General Rate Increase, In the Matter of Petition of Virginia Electric and Power Company d/b/a Dominion North Carolina Power for an Adjustment of Rates, Docket No. E-22, Sub 479 (Dec. 21, 2012). The Commission finds that the AGO's intergenerational equity argument is unpersuasive. The Commission takes judicial notice that DEP's electricity rates are low compared to the national average. This result is due to DEP's historic use of coal generation. The regulations requiring action to clean up the CCRs were not in effect ten or fifteen years ago. Rather, DEP's obligation has arisen in 2014 and 2015 and DEP is taking appropriate actions to comply.

The Commission gives significant weight to the testimony of witnesses Bateman and Maness. As a result, the Commission approves DEP's request to establish a deferral account for the deferral of prudently incurred CCR costs, a return on that deferred account at the Company's authorized overall cost of capital approved in this Order, and application of the mid-month cash flow convention recommended by the Public Staff.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 53-56

The evidence supporting these findings of fact and conclusions is contained in the Application, Form E-1, the testimony of the public witnesses, and the testimony and exhibits of the following expert witnesses: DEP witnesses Fountain, Bateman, Kerin, Wells and Wright; Public Staff witnesses Lucas, Garrett and Moore, Peedin and Maness; AGO witness Wittliff; CUCA witness O'Donnell; and Sierra Club witness Quarles.

The public witness testimony and expert witness testimony and exhibits regarding DEP's coal combustion residuals (CCR) 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 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 $30 million should be assessed for DEP's mismanagement of its CCR activities undertaken through the end of the test year as extended for reasons set forth hereafter.

DEP has relied upon coal-fired power plants throughout its history, and depends upon coal-fired generation today. Coal ash, also known as coal combustion residuals, or CCRs, is a by-product of coal-fired generation. Since the 1950s, standard industry practice at least in the Southeast, has been to deposit coal ash in coal ash basins, and such basins were constructed and were and are used at all of the Company's coal-fired generating units.

The United States Environmental Protection Agency (EPA) has studied CCRs and their proper management and handling since the 1980s and began moving forward on comprehensive regulation of CCRs approximately ten years ago. In 2010, the EPA issued proposed rules regarding CCRs. EPA's final rule – the Coal Combustion Residuals Rule (CCR Rule) – was promulgated on April 17, 2015. North Carolina also enacted specific statutory requirements for coal ash management in its Coal Ash Management Act (CAMA), which became effective in 2014 and was amended in 2016. The CCR Rule and CAMA introduced new requirements for the management of coal ash. DEP 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 Asset Retirement Obligation (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-2, Sub 826, deferred the impacts of its GAAP-mandated ARO accounting. The Company seeks recovery of the coal ash basin closure costs incurred to date in connection with CCR Rule and/or CAMA compliance, along with such costs it anticipates will be incurred annually on an ongoing basis. The Company's proposal has three component parts:

- First, DEP seeks recovery of the actual coal ash basin closure costs it incurred from January 1, 2015 through August 31, 2017. On a North Carolina retail jurisdiction basis, these costs (netted against the amount already included in the Company's rates following its last rate case) amount to $241.9 million.[16] 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, DEP seeks to recover on an ongoing basis $129.1 million per year in annual coal ash basin closure spend. This amount is based upon DEP's calculation of the NC retail jurisdiction portion of the test year (2016) coal ash basin closure expense incurred by the Company.

- Third, DEP 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 $129.1 million, if the Company's proposal as detailed above is approved by the Commission. In addition, the costs incurred from September 1, 2017 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.

For cost recovery, a utility must show 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. Once shown, and, assuming no penalty for mismanagement, the utility is entitled to recover the costs so incurred.

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 a theory that cost recovery should be shared by both the shareholders and ratepayers.

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[16] This amount excludes any fines, penalties and other unrecoverable costs incurred by the Company. (Tr. Vol. 6, p. 122.)

Summary of the Evidence

1. Company Direct Case Overview and Costs Sought for Recovery

In his direct testimony, Company witness Fountain testified that the Company is requesting recovery of coal ash basin closure compliance costs incurred in the period from January 1, 2015 through August 31, 2017. He stated that the Company is seeking recovery of these costs over a five-year period in order to mitigate the associated customer rate impacts. (Tr. Vol. 6, p. 41.) Witness Fountain clarified that this case excludes any fines or penalties incurred by DEP related to coal ash basin closure or management. (Id. at 40 n.2, 224.) Witness Fountain also testified on direct that, based on actual coal ash expenses incurred during the 2016 test year, DEP is seeking recovery of ongoing coal ash basin closure compliance spend of $129.1 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 41-42.)

Company witness Bateman testified that the Company is currently collecting costs associated with the closure of coal ash ponds in the cost of removal portion of its depreciation rates. These cost of removal rates were based on estimated closure costs included in the 2012 dismantlement studies prepared for the Company by Burns & McDonnell, a third-party engineering firm. These cost estimates were prepared prior to CAMA's enactment and the EPA's CCR Rule, and were based on the industry standards and best practices recommended by the engineering consultants at the time. Since that time, CAMA and the CCR Rule have increased the estimated closure costs for the Company's coal ash ponds, and changed the required accounting treatment, triggering asset retirement obligation accounting. For these reasons, she explained that the coal ash pond closure costs have been removed from the depreciation rates, and are instead being requested as proposed in her Adjustment Nos. 18 and 19. (Tr. Vol. 6, pp. 117- 19.)

Adjustment No. 18, as updated, is the actual coal ash basin closure costs incurred by the Company from January 1, 2015 through August 31, 2017. On a North Carolina retail jurisdiction basis, these costs (netted against the amount already included in the Company's rates following its last rate case) amount to $241.9 million. (See Maness Late-Filed Ex. submitted by the Public Staff on December 22, 2017 and accepted by the Commission on January 2, 2018.) Witness Bateman explained that her adjustment No. 18 amortizes the deferred coal ash costs over a 5-year period, and includes a return on the unamortized balance.

Adjustment 19 represents the amount in ongoing annual coal ash basin closure expense (sometimes referred to in this Order as "run rate" or "ongoing compliance costs"). The number is based upon actual test year (2016) spend, and witness Bateman testified that the Company expects to incur actual ongoing compliance costs that exceed this level. (Tr. Vol. 6, pp. 144-45.) As set out in Maness Late-Filed Exhibit, the final and updated amount requested by the Company is $129.1 million.

2. Company Direct Case: Coal Ash Overview

Company witness Kerin provided a discussion of DEP'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 in coal-fired power 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 over time, affecting how the Company has operated its coal-fired plants in compliance with those obligations. He described the steps in the environmental regulatory evolution process. He testified that, in his opinion, DEP was in line with industry standards and has reasonably and prudently managed CCRs and its coal ash basins. He explained that since its last rate case, DEP has become subject to both federal and state regulations that require it to take significant action to close its coal ash basins. (Tr. Vol. 16, pp. 103-05, 107-09.)

Witness Kerin testified that since the 1920s, DEP 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 from boilers and stored in landfills. Since that time, the industry transitioned to a water sluice to remove coal ash from boilers, and to clean the electrostatic precipitators, preventing coal ash from being emitted through the smokestacks. This effluent, as well as FGD blowdown, was then diverted to coal ash basins, of which DEP has 19 in the Carolinas. In other words, in many cases, coal 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. 16, 108-09.)

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 coal ash handling and coal ash basins the primary lawful and effective way to meet CCR needs and environmental requirements from 1974 until 2015.

Witness Kerin testified that the Company has begun the process of closing, or submitting plans to close, its coal ash basins in accordance with the program with the most limiting requirements. Witness Kerin also testified that coal-powered electric generation has since ceased at five of the eight coal-fired DEP generating facilities with coal ash basins, including the Cape Fear, H.F. Lee, Robinson, Sutton, and Weatherspoon plants. (Id. at 107-08.)

Witness Kerin testified that in addition to the CCR Rule and CAMA, DEP is also subject to other CCR-related obligations that result from state environmental regulatory oversight under existing rules and regulations. For DEP, in South Carolina, there is one

Consent Agreement with the South Carolina Department of Health and Environment (DHEC) applicable to ash management at the Robinson plant. The Robinson Consent Agreement, DHEC 15-23-HW, between Duke Energy Progress, Inc. (now Duke Energy Progress, LLC) and DHEC, requires coal ash excavation of a 1960 lay-of-land coal ash storage area located south of the coal ash basin. This Consent Agreement also includes provisions to initiate permitting of an on-site lined CCR landfill to store the excavated coal ash. (Tr. Vol. 16, p. 133.)

Witness Kerin noted that there is 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 actions and draft rules applicable to many utilities, not just Duke Energy, were being developed prior to 2014, and that the Company now confronts another wave in the evolution of environmental regulation pertaining to coal 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 August 31, 2017, and recovery of ongoing compliance costs. He testified 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 coal ash basin site at issue. He testified further that each of the Company's historical and ongoing CCR compliance costs are reasonable, prudent, and cost effective given the individual facts and circumstances at each power plant and coal ash basin site at issue. (Id. at 106.)

Witness Kerin explained that the requirements under CAMA, as amended, the CCR Rule, and the consent agreements (the "CCR Compliance Requirements") affect how the coal-fired power plants operate, and that they effectively require the coal ash basins to be retired. He stated that in regard to coal ash basin operation, modifications to the power plants are required to direct storm water flow away from the coal ash basins, and to cease bottom ash and fly ash sluice flow to the basins. As the coal ash basins are closed, other process streams, such as low-volume wastewater, coal pile run-off, and FGD blowdown flows, as examples, must also be directed away from the coal ash basins to facilitate dewatering and closure. (Id. at 136.)

Witness Kerin stated that coal ash removal has been initiated at several DEP stations, including the Asheville Plant, and the Sutton Plant. 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, DHEC or DEQ, prior to beginning coal ash excavations. As the CCR Rule and CAMA lead to coal ash basin closure, preparations are required to transition the coal-fired generating sites for this outcome. Operating coal-fired power plants in the Carolinas requires plant modifications to fully transition to dry ash handling in order to cease sluice flow to the coal ash basins.

All coal-fired power plants, even those retired, require some level of modification to cease all flows to the 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. (Id. at 136- 37.)

Witness Kerin described the closure plans and site analysis and removal plans developed by DEP to physically close the coal 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 Comprehensive Site Assessments, and the groundwater corrective actions required in the Corrective Action Plans. Coal ash basins can be closed by excavation, with the coal ash permanently stored in a CCR landfill or used in a beneficial way such as a structural fill or for cementitious purposes. Coal ash basins can also be closed by capping the CCRs in place. (Id. at 137.)

Witness Kerin also stated 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 DEQ under the CAMA regulatory process. He explained that the state-mandated closure plans are reviewed and approved by DHEC 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 coal 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. (Id. at 137-38.)

Company witness Kerin testified that in Exhibits 10 and 11 to his testimony, he broke the coal ash pond closure costs already incurred or expected to be incurred prior to August 31, 2017, down into their core components and have described the plants to which these costs apply. In detailing these costs, he also provided narrative summaries as to why, in his opinion, 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 testified that these exhibits, coupled with the balance of his testimony and exhibits, demonstrate that these costs are reasonable and prudent. (Id. at 140.)

Company witness Kerin explained that, in his opinion, DEP's historical handling of CCRs was reasonable, prudent, and consistent with industry standards over time. He stated that, in his opinion, this demonstrates that nothing that DEP has done historically is causing the Company to incur any unjustified costs today to comply with post-2015 CCR regulations. (Id. at 143.) 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 percent, 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. Witness Kerin testified that 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.

He maintained that Duke Energy's practices have been and continue to be consistent with those of the industry. Similar to the industry, according to witness Kerin, DEP has on-site CCR landfills that are actively receiving production fly ash, and some bottom ash, at specific coal-fired generating sites, including the Mayo and Roxboro Plants in the Carolinas. Also, similar to the industry, he testified that DEP has active coal ash basins still receiving bottom ash, and some fly ash, at specific coal-fired generating sites, including the Asheville Plant, Mayo Plant, and the Roxboro Plant in the Carolinas. The coal ash handling practices for ash basins and ash landfills in the Carolinas are, in his opinion, consistent with the applicable regulatory requirements that were in effect during the history of these CCR units. (Tr. Vol. 16, pp. 118-19.)

Witness Kerin also maintained that DEP'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. He testified that the historical and current CCR handling and use of CCR basins is consistent across these legacy companies that make up Duke Energy Corporation today, and consistent with the industry. (Tr. Vol. 16, p. 119.)

Company witness Wright noted that coal ash use and disposal have 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. 13, 361-62.)

3. <u>Company Direct: Cost Recovery Overview</u>

Witness Wright also testified that, in part, as a response to an accident at a surface impoundment at Tennessee Valley Authority's ("TVA") Kingston Fossil Plant in

Harriman, Tennessee, the EPA published in the Federal Register proposed new coal ash disposal regulations for CCRs. The proposed regulations specifically referenced the TVA incident as a major reason for the proposed rule, and EPA discussed several other coal ash incidents that led to the promulgation of the rule. Witness Wright noted 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 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, referenced the Dan River accident, without indicating that the accident modified the proposed rule. (Tr. Vol. 13, pp. 362-63.)

He 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 the EPA's and the CAMA rules are "largely duplicative," the Company 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. 13, pp. 363-64.)

Witness Wright testified that, in his opinion, 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 stated that G.S. 62-133(b) embodies this principle. He stated 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 stated that environmental compliance costs are similar to other costs that a utility might spend in producing and delivering power. He explained 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 that have long been deemed recoverable for utilities across the country, including DEP. (Id. at 354.)

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 stated 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. (Id. at 358-60.)

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.

However, according to witness Wright, it is important to make sure that the costs underlying or directly causing such fines or penalties be separated from prudently incurred, ongoing costs. For example, if a generating plant received a fine, then by no means should that fine be recoverable. But the fact that a fine was given does not mean that the ongoing, prudently- incurred costs necessary to produce generation should be disallowed. (Id. at 361.)

He further explained why, in his view, 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 evidence in the final rule that the Dan River accident changed or modified the EPA's proposed rule. He testified that both the proposed rule and the final rule addressed the need for imposing corrective action at inactive facilities, and stated 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. (Id. at 363-65.)

Witness Wright also testified that, in terms of timing, the new state CAMA coal ash standards did result from the Dan River spill, but, in his view, 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 North Carolina 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, the North Carolina Legislature and/or the State's DEQ would likely have taken steps to adopt some coal ash regulations shortly after the CCR Rule was finalized in 2015 simply because of the CCR Rule's encouragement to do so. He concluded that the timing of CAMA was certainly influenced by the Dan River accident, but also stated his belief that, even without the Dan River accident, the state would likely have adopted some new coal ash disposal standards in the 2015 timeframe simply in response to the CCR rules, as it did just a few years prior to adopting CAMA, when it adopted coal-fired generating facility environmental standards in the Clean Smokestacks Act that were stricter than the federal standards at the time. He stated that, regardless, the Company must comply with both the federal and state coal ash disposal standards. (Id. at 366-67.)

In his direct testimony, Company witness Wright testified that in his opinion the coal ash disposal costs that DEP seeks to recover in this case are "used and useful" utility cost. (Tr. Vol. 13, p. 375.) He explained that DEP's coal ash disposal sites have always been used and useful as part of the coal-fired generation production process. He noted that G.S. 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 included in rate base, the cost must be both reasonable and incurred for property that is used and useful in providing service to customers. He stated that the Company has historically spent dollars in order to comply with the coal ash disposal regulations in effect at the time, and these dollars were a necessary expenditure related to used and useful utility costs made in the provision of electric service at the time. (Id. at 375-76.) The Company was, and continues to be, in his view, 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 DEP seeks recovery in this case, "used and useful" in providing electric service. (Id. at 376.) He stated that this conclusion 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 376-78.)

Company witness Wright also noted that the Commission addressed this exact coal ash disposal cost issue in its December 22, 2016 Order in Dominion's recent rate case, Docket No. E- 22, Sub 532. 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. A third important point decided by the Commission in the Dominion case, he maintained, was that the prior coal ash disposal assets were used and useful. Finally, similar to what DEP is requesting in this rate case, the Dominion 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. (Id. at 378-79.)

4. The Positions of Intervenor Parties other than the Public Staff

AGO witness Wittliff testified that DEP's actions and inactions were largely responsible for the stringent conditions of CAMA, which he said accelerated remediation and closures and narrowed the field of removal and closure options. (Tr. Vol. 15, p. 24.) He claimed that the Company's actions also led to inadequate operations and a failure to meet industry standards in how its coal ash basins complied with permits, which he argued resulted in CCR remediation and closure costs that exceeded what would have occurred absent the Company's actions. He also contended that if DEP had prudently managed its CCRs and associated impoundments, it would have been allowed to implement less expensive remediation and closure options over a longer period of time under the CCR Rule. He opined that DEP imprudently managed its facilities and that such mismanagement is causally linked to costs that should be disallowed in this case. He asserted that due to CAMA's identification of Sutton and Asheville as high priority sites, and the resulting acceleration of closure at those sites, approximately 72%, or about $224 million of the total ARO expenditures by DEP in 2015 and 2016 were for these two sites, part of which was for the transportation by rail and by truck of a significant portion of those sites' CCRs offsite. (Id. at 24-58, 60-62.)

CUCA witness O'Donnell purported to compare the DEP 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 the highest in the nation, and contended that the only discernable difference between DEP and the other utilities in his comparison was CAMA, which he asserted was prompted by the Dan River spill. He stated that DEP did not provide a similar financial analysis for this case. (Tr. Vol. 15, pp. 230-31.) Witness O'Donnell opined that DEP 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. 16, p. 18.)

Sierra Club witness Quarles evaluated the methods DEP has proposed to close existing coal ash ponds at the Mayo and Roxboro plants and opined as to environmental conditions that may be associated with capping those ponds in place. He asserted that continued storage of coal ash at Roxboro and Mayo poses significant environmental risks. He stated that the unlined basins at these plants were constructed over natural bodies of water, between 60 and 90 feet of the coal ash stored in the basins there is submerged in groundwater, and groundwater flows into those basins from topographically higher elevations and will come into 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 coal ash basins would reduce the concentrations and extent of this contamination. (Tr. Vol. 13, pp. 132-73, 175- 77.) On cross-examination, witness Quarles conceded that excavation and moving the coal ash at Mayo and Roxboro to lined landfills would increase the cost for closure. (Id. at 180.) Also, he agreed that with learning, advancement, and improved capability, changes and advancements can follow. (Id. at 190.) He admitted that his evaluation was conducted from a distance rather than by interaction with the Company. (Id. at 193-94.) He agreed that boron is a naturally occurring element in the soils in locations like Mayo and Roxboro. (Id. at 194.) Witness Quarles agreed that the CCR Rule was not the first time that the EPA discovered that utilities nationwide were using unlined wet coal ash basins, and that while the EPA was studying the issue at least as early as the 1980s, it took action to regulate coal ash basins only a few years ago. (Id. at 200-01.) He also recognized that utilities have been permitted to dispose of coal ash in unlined basins. (Id. at 190-99, 204.)

In its post-hearing Brief, the AGO contends that ratepayers should not be forced to cover costs caused by DEP's years of failure in managing coal ash basins. The AGO argues that Commission needs to consider whether the costs incurred are reasonable and prudent. When making this determination, the AGO states that the Commission must ask whether the utility acted prudently over time as coal ash was generated and stored or if prior mismanagement or negligence by the utility has impacted the work that needs to be done now. The Commission must also determine whether DEP's current actions to cleanup are reasonable and prudent.

The AGO states that coal has been utilized for many decades and beginning in approximately 1950, DEP, like many utilities, used unlined earthen impoundments to deposit its CCRs. The AGO indicates that the use of coal grew significantly over the years with over 60 million tons of coal ash produced annually in the United States in the 1970's and by 1988, it was predicted that in 2000, the annual coal waste could reach 120 million tons of coal ash. The AGO cites to the 1988 EPA report to Congress which pointed out that in North Carolina, solid waste regulations exclude surface impoundments and defer to state water laws for regulatory authority. Therefore, DEP was bound by the regulatory requirements of its NPDES permits. The AGO points to the 1988 report to posit that the lining of the surface impoundments was becoming a more common practice and indicated that DEP still only has one lined impoundment to date.

The AGO states that DEP failed to keep pace with industry standards. First, the AGO argues that DEP had a lackadaisical response to 2L standards, passed in 1979. In testimony, DEP indicated that there was no obligation to monitor groundwater quality under the 2L regulations; the obligation to take corrective action arises after exceedances have been identified. The AGO identified that the groundwater monitoring requirements were not immediately added to all of the Company's NPDES permits by DEQ, and the Company indicated that it was under no obligation to monitor for groundwater impacts and only voluntarily did so as required by site specific conditions. The AGO argues that the Company, except at a few sites, did not voluntarily monitor groundwater until the requirement was put into the NPDES permit.

Second, the AGO cites to the failure at the Roxboro plant from 1966 to 1990 at the Hyco Reservoir, which the EPA cited as a proven damage case used in support 2015 CCR rule. Third, the AGO states that in 1996 DEP entered into standstill agreements with two insurance carriers recognizing potential legal exposure from its CCR ponds. Fourth, the AGO outlines the seeps that DEP allowed to occur at its basins, including the seeps to which DEP pled guilty to in federal court, the 200 seeps that were identified in permit modification applications filed in 2014, and seeps found in dam safety inspections in the late 1990's and early 2000's. Fifth, the AGO cites to a November 2004 Sutton Report that was prepared because the 1984 lined coal ash pond was running out of capacity. The report indicated that the 1984 pond is currently estimated to be non-operational due to reaching capacity limits by June 2006. The AGO argues that DEP knew that the ponds were creating an environmental hazard and chose to ignore them. Next, the AGO states that after the TVA coal ash dam [dike] failure, EPA came and inspected DEP's ponds with negative findings, specifically finding that 75% of DEP's ponds were rated as poor. Duke, upon questioning at the time, indicated that poor also applies to further critical studies or investigation that are needed to identify safety deficiencies. The AGO identifies that DEP pled guilty in federal court and even though DEP is not to receive any NOVs as part of the criminal plea, DEP has received three NOVs at its Asheville plant.

Next, the AGO argues that these failures by DEP led to the passage of CAMA and the CCR rule, which in turn led to increased costs. Specifically, Kerin's testimony suggests that approximately 72% of the current expenditures are for the accelerated schedules, and Garrett and Moore testified to specific disallowances of Sutton and Asheville.

The AGO reiterates that DEP has not met its burden of showing costs are reasonable and prudent, but rather these new costs are attributable to unlawful and imprudent behavior. Lastly, the AGO argues that the Clean Smokestacks Act dealt with operating plants and here most plants are retired so no supports exist under that Act.

The AGO contends that DEP is not entitled to special cost recovery. DEP was recovering these costs in depreciation expense through amortization for retired plants. The AGO cites to the Burns & McDonnell 2012 dismantlement studies indicating lower estimated closure costs, based upon dewatering and capping in place. The AGO states that now that recovery for closure costs is much greater, DEP seeks a special accounting method. The AGO argues that imposing these coal ash costs on current ratepayers raises intergenerational fairness given DEP'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.

In addition, the AGO submits that DEP 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 special operating expenses. According to the AGO, operating expenses are recoverable without return pursuant to G.S. 62-133(b)(3) and State ex rel. Utilities Commission v. Thornburg (Thornburg I), 325 N.C. 463, 475, 385 S.E.2d 451, 458. Further, the AGO submits that the unamortized balance of the CCR deferred costs are similar to those considered in State ex rel. Utilities Comm. v. Carolina Water, 335 N.C. 493, 507, 439 S.E.2d 127, 135 (1994) (Carolina Water), where the Supreme Court considered whether the Commission erred when it treated utility plant that was not in service at the end of the test year – and would not be returned to service – as "an extraordinary property retirement," allowed amortization of the unrecoverable costs over ten years, and included the unamortized portion in rate base. The Court concluded that the costs were for plant that was not used or useful and, thus, the unamortized costs should not have been included in rate base. As the Supreme Court explained: "Including [these] costs in rate base allows the company to earn a return on its investment at the expense of the ratepayers." Id. at 508, 439 S.E.2d at 135 (citations omitted).

Finally, the AGO notes that a similar issue was considered by the Commission in the 2016 DNCP general rate case relating to rate base treatment of the unamortized balance during CCR cost recovery, wherein the Commission distinguished the circumstances in Carolina Water. The AGO contends that the Commission's decision in the DNCP case should not set the standard for the present case because the determination was allowed under the circumstances presented in that case without precedential effect regarding the treatment of CCR costs in future proceedings.

In its post-hearing Brief, CUCA contends that DEP's request for 100% CAMA compliance cost recovery is not appropriate. CUCA submits that DEP's costs are overstated and that many are the result of DEP's negligence, which is most clearly highlighted in DEP'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. CUCA states that a 25% recovery is equitable. CUCA argues that this case is different than the DNCP rate case. DEP is different than Dominion in the used and useful analysis in that Dominion never had a coal ash spill, did not plead guilty to Clean Water Act violations, did not pay $102 million for mismanagement, and did not admit that CAMA was passed due to the Dan River spill. 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, DEP should not have pursued regulatory closure of operating sites.

Sierra Club, in its post-hearing Brief, argues that closure of DEP's coal ash ponds is necessary to address unlawful discharges to surface waters and therefore closure costs are not recoverable, citing G.S. 62-133.13. Further, Sierra Club contends that all of the CCR basins are unlawfully discharging pollutants into surface waters and the only way to stop these unlawful discharges is to close the pond and eliminate the source, the coal ash. Therefore, the costs of pond closure results from the unlawful discharges and are not recoverable.

In addition, Sierra Club submits that DEP has failed to meet its burden of demonstrating that its proposed rates are just and reasonable in that no evidence exists to prove that storage of coal ash in unlined, leaking ponds for decades was a reasonable and prudent way for DEP to manage its CCRs. According to Sierra Club, the only evidence provided was Kerin's bold assertion that historical handling of CCRs was reasonable, prudent and consistent with industry standards over time. Sierra Club cites to the Commission's ratemaking decision regarding MGP clean-up asserting that when determining ratepayer responsibility, the prudency of the Company's initial operation of each site should be considered. In that case, the Commission found prudent operation. In contrast, the Sierra Club states that the record shows a history of mismanagement with respect to coal ash basins, citing seeps at almost all of its ash ponds as being unlawful discharges that violate the federal Clean Water Act and Section 143-215.1 of the North Carolina General Statutes, and the terms of DEP's NPDES permits. Sierra Club maintains that the operation of a system meant to treat wastewater in a manner that allows the release of untreated wastewater and repeated violations of the law cannot be considered prudent, and that DEP provided no evidence on whether its prior CCR management practices have resulted in unjustified costs.

Moreover, Sierra Club argues that DEP's closure plans for its Mayo and Roxboro ash basins do not comply with the CCR Rule or protect against continued discharges, and, therefore, DEP's proposed run rate should be rejected.

Sierra Club also contends that capping in place the Mayo and Roxboro CCR basins will not protect against continued leaching of coal ash constituents into groundwater or into surface waters through migration. Therefore, it submits that DEP's closure plans violate the CCR Rule. Sierra Club notes that there are two federal lawsuits pending on this issue, and that a closure plan that does not protect against future contamination cannot be considered prudent. DEP's run rate is based upon the assumption that ash ponds at Mayo and Roxboro will be capped in place. Therefore it is not reasonable to approve an ongoing run rate for future cleanup when the full scope of those costs is not understood. Therefore, according to Sierra Club DEP's request for a run rate based upon the assumption that the ash ponds at Mayo and Roxboro will be capped in place should be rejected.

In its post-hearing Brief, NC WARN contends that DEP should be severely limited on coal ash cost recovery. NC WARN asserts that none of the costs associated with coal ash mitigation and cleanup should be borne by ratepayers, and that DEP should not make profits on selling coal ash from its existing coal ash basins as part of a permanent disposal scheme.

In its post-hearing Brief, Fayetteville PWC suggests that the Commission impose a provisional deferral of costs in an amount equal to DEP's insurance coverage for such remediation liabilities, which costs may not be recovered from ratepayers unless or until DEP either recovers offsetting insurance proceeds or demonstrates that DEP's own actions or omissions did not result in a denial of insurance coverage or a reduced settlement for its coal ash remediation costs. Fayetteville PWC also requests that the Commission adopt the coal ash remediation costs disallowances and deferral recommended by the Public Staff and order the sharing of coal ash remediation costs between DEP's shareholders and ratepayers in the manner recommended by Public Staff.

In its post-hearing Brief, CIGFUR argues that DEP 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 states that the total cost to defer is $260.3 million and that the carrying charges associated with the incurred coal ash costs since 2015 are $9.4 million, $1.9 million is associated with the cost of debt and $7.5 million is associated with the cost of equity. CIGFUR further states that amortizing over 5 years results in annual amortization expense of $52.1 million, plus a $14.4 million net tax return, for a total requested revenue requirement of $66.5 million for deferred coal ash pond closure costs. CIGFUR 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 DEP's ratepayers and is inappropriate for such a significant expense that fails to enhance reliable service. CIGFUR 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 argues that DEP should not recover the run rate of $129.1 million and that DEP should defer ongoing costs for future recovery in its next rate case. CIGFUR opposes any carrying costs on the deferred amounts because the deferred amounts are not capital costs and that it is more appropriate to allow a $1 for $1 recovery and no more.

In its post-hearing Brief, Quad Towns states that the Commission must determine whether the initial operation of each site was prudent, as discussed in the Commission's MGP case. Quad Towns contends that most intervenors argued that DEP's demonstrated and criminally negligent failure to prudently and reasonably manage its CCR impoundments was the driving force for the enactment of CAMA, which increased the costs. Thus, these costs were not prudently incurred because if DEP had prudently managed its sites, these costs would have been avoided.

Further, Quad Towns notes that DEP argues that additional safeguarding in the past would have been deemed gold-plating and any such costs would have been deemed imprudently incurred. According to Quad Towns, given the fact that DEP had 485 NPDES permit violations, over 200 documented seeps and 2,857 2L violations, it is hard to assume that additional safeguards would have been gold-plating.

In addition, Quad Towns argues that costs arising out of mismanagement of a long-lived asset are not appropriate for deferral accounting, and notes that Section A13 of FASB states that obligations resulting from improper operations do not represent costs that are an integral part of the asset. The section goes on to state some spillage is acceptable, but the obligation to clean up after a catastrophic accident does not result from the normal operation of the facility. Because such costs are not appropriate for deferral, the costs should be borne by shareholders. Quad Towns states that it interprets the section language broader than the given example of a catastrophic accident.

Quad Towns also argues that the Commission cannot police the utilities' day to day operations to ensure that it is prudently managing its facilities in a safe and environmentally appropriate manner, and that the only way that the Commission can protect ratepayers from exorbitant rate increases due to mismanagement of utility operations is to disallow those costs that are attributable to the mismanagement.

Quad Towns supports a 75% disallowance of the historic costs based upon CUCA witness O'Donnell's testimony, and the same result but different analysis of AGO witness Witliff. It notes that witness Witliff testified that specifically looking at the Sutton and Asheville sites designated as high priority by CAMA, DEP spent approximately 72% more due solely to the accelerated timeline and DEP choosing to move the coal ash offsite. As further support, DEP's 2012 dismantlement study, after the 2010 CCR Rule was proposed, concluded that a $10 million depreciation expense would suffice to address end-of-life costs. Therefore, costs above $10 million earmarked in 2012 are attributable to the more costly CAMA closure requirements. Further, Quad Towns supports the specific Garrett and Moore disallowances.

For future costs, Quad Towns supports the Public Staff's 50/50 sharing proposal, and states that cost sharing is appropriate because: (1) DEP failed to prevent environmental contamination from its impoundments in violation of state and federal law, and (2) there is a history of approval for sharing extremely large costs that do not result in new generation of electricity for customers, such as the MGP case.

Moreover, Quad Towns argues that DEP saying its actions were in accordance with industry practice is incompatible with DEP's admissions in federal court to criminal actions that DEP "failed to exercise the degree of care that someone with ordinary prudence would have exercised in the same circumstance with respect to…" management of various aspects of its coal ash impoundments, and acted negligently in failing to prevent unauthorized discharges and to follow the conditions of its permits.

Further, Quad Towns argues that the Commission should disallow any recovery of CCR costs through the fuel adjustment clause, based on the fact that no cost was assigned to coal ash in the Charah contract with DEP. Rather the contract supports payment for coal ash remediation. Further, according to Quad Towns the evidence tends to show that Charah purchased the Brickhaven mine for the singular purpose of disposing of CCRs. Therefore, there was not an independent need for fill dirt.

Lastly, Quad Towns requests that the Commission specify the amount of disallowance. For example, if the Commission chooses to disallow a certain amount of CCR costs through amortization, if the Commission can clearly specify the amount of disallowance first and then explain that the disallowance is being achieved by the extended amortization, it will assist in avoiding future litigation over language in Quad Towns' wholesale purchase power agreements. Quad Towns states that if the Commission disallows 50% of DEP's request, Quad Town's customers will save approximately $309,902.50.

5. 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 DEP with respect to its coal ash management. In addition, they reviewed the approach taken by DEP to determine the least cost method of achieving compliance with the laws and regulations governing coal ash management. In conducting their investigation, witnesses Garrett and Moore reviewed the closure plans and coal ash-related costs incurred for all of DEP's coal-fired facilities, conducted extensive discovery, participated in numerous meetings, and visited several of the DEP facilities in question. (Tr. Vol. 18, pp. 133-34.)

Witnesses Garrett and Moore did not take exception with DEP 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 DEP that were not required by law or where lower-cost compliance options were available. Witnesses Garrett and Moore did not take exception with DEP's selected closure method for the coal ash basins at the Robinson Plant in South Carolina, which is subject to a consent agreement entered into between DEP and the South Carolina Department of Health and Environmental Control (DHEC). (Tr. Vol. 18, p 139.)

With regard to DEP's Mayo and Roxboro plants, witnesses Garrett and Moore noted that DEQ issued final classifications for these facilities as Intermediate Risk in May 2016, and that DEP is in the process of establishing the permanent replacement water supplies required under G.S. 130A-309.211(c)(1) and performing the applicable dam safety repair work at these sites. Upon completion of these tasks within the timeframe provided, the impoundments at these facilities will be reclassified as low-risk pursuant to G.S. 130A-309.213(d)(1). They 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. Witnesses Garrett and Moore noted that this approach is generally the most cost-effective means for closure of a CCR unit. They 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 DEP has not submitted a Site Analysis and Removal Plan (SARP) to DEQ for any facilities other than Sutton and Asheville at this time. Therefore, a prudence review of the Mayo and Roxboro closure plans would be premature, so witnesses Garrett and Moore took no exception in the present case to DEP's current proposed closure method for the coal ash basins located at Ma**y**o and Roxboro. (Tr. Vol. 18, pp. 139-41.)

In addition, Public Staff witnesses Garrett and Moore did not take exception to DEP's closure method for the CCR units located at Cape Fear and H. F. Lee. DEP has selected the Cape Fear and H. F. Lee Stations as two of the three beneficiation sites pursuant to G.S. 130A-309.216, which required Duke Energy to identify three sites located within the state with coal ash stored in the impoundments suitable for processing for cementitious purposes. Upon selection of the sites, Duke Energy was required to enter into a binding agreement for the installation and operation of coal ash beneficiation projects at each site capable of annually processing 300,000 tons of coal ash to specifications appropriate for cementitious products, with all processed coal ash to be removed from the impoundments located at the sites. (Tr. Vol. 18, pp. 141-43) Witnesses Garrett and Moore also noted that the timeframe proposed by DEP for beneficiation of the Intermediate Risk sites extends beyond the closure timeframe called for in Section 3.(a) of S.L. 2016- 95 for sites deemed Intermediate Risk, and that G.S. 130A-309.215 provides a variance option for closure deadlines that are found to be in the public interest. (Id.*)*

Public Staff witnesses Garrett and Moore testified that they did not take exception to DEP's closure method for the CCR units located at Weatherspoon, where DEP 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. They noted that this option appears to offer a lower cost than other closure options for the site, and believe that DEP should have sought to establish Weatherspoon as one of the three beneficiation sites as required by G.S. 130A-309.216. This would have allowed the DEC Buck Station, which was instead selected as the third beneficiation site, to utilize significantly lower cost closure options instead of cementitious beneficiation. Witnesses Garrett and Moore testified that DEP indicated in response to data requests that it could only obtain guaranteed commitments for 230,000 tons of coal ash per year, as opposed to the 300,000 required by statute. They indicated that the potential cost savings associated with selecting Buck for closure options other than beneficiation would have justified making additional efforts to identify additional sites for beneficial reuse of coal ash of the additional 70,000 tons of coal ash from Weatherspoon. (Tr. Vol. 18, pp. 143-44.)

With regard to DEP's selected closure actions at the Sutton Plant, witnesses Garrett and Moore took exception with DEP's decision to excavate and transport coal ash off-site to the Brickhaven structural fill facility in Chatham County. They contended that had DEP expeditiously pursued an on-site industrial landfill at the time it began working on the structural fill facility, it could have disposed of all of the coal ash on-site without incurring the added expense associated with the off-site transfer and disposal. (Tr. Vol. 18, pp. 153-55.)

Witnesses Garrett and Moore disputed DEP'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 DEP's ability to construct an on-site greenfield landfill at Sutton in a timely fashion. They evaluated the timeframe for which DEP would have had to construct the landfill and determined that based on DEP's assumptions regarding landfill permitting and construction timeframes, along with the excavation and placement rates estimated by DEP in its analysis of the facility, DEP could have handled all of the coal ash on-site without having to incur the significant costs associated with off-site transportation costs and construction of rail handling equipment. (Tr. Vol. 18, pp. 145-48.)

Witnesses Garrett and Moore also took exception with DEP's inclusion of costs associated with two specific liner components, called the "Secondary Geocomposite Layer" and "Secondary 60-mil HDPE 9 Textured Geomembrane Material" that were included in DEP's current on-site landfill construction contract. They testified that these secondary layers exceed what is required under federal and state regulations. Therefore, witnesses Garrett and Moore recommended that the costs associated with these secondary liner layers be disallowed. (Tr. Vol. 18, p. 154.)

As a result of DEP's unnecessary actions to transport coal ash off-site from the Sutton facility and to install landfill liner components that exceeded regulatory requirements, witnesses Garrett and Moore recommended a total disallowance at the Sutton facility of $80.5 million from DEP's coal ash expenditures during this recovery period. (Public Staff Garrett and Moore Exhibit 7)

Witnesses Garrett and Moore summarized the coal ash closure approach taken by DEP at its Asheville facility. They testified that DEP had been excavating coal ash from the 1982 Ash Basin since 2007 in order to provide structural fill material for the Asheville Regional Airport, transporting this material by truck. Following passage of CAMA in 2014, which deemed Asheville a High-Priority site subject to an August 2019 closure date, DEP continued to excavate coal ash and transport it off-site while the potential for an on-site landfill was evaluated. However, passage of the Mountain Energy Act of 2015 (S.L. 2015-110, hereinafter the "MEA") amended the required completion date for closing the two coal ash basins to August 1, 2022, to allow time for the construction of a combined cycle plant on the site, and retirement of the existing coal-fired generating station. (Tr. Vol. 18, pp. 155-56.)

In their direct testimony, witnesses Garrett and Moore took exception with DEP's decision not to pursue an on-site industrial landfill at the Asheville site, on the basis that DEP could have avoided incurring significant off-site transportation costs. Witnesses Garrett and Moore noted that while the design and construction of an on-site industrial landfill at the Asheville facility would have been technically challenging, they believed that it could be done at a lower cost than transporting the remaining coal ash materials off- site. Witnesses Garrett and Moore also testified that the coal ash processing costs expended at the Asheville facility relative to the amount of coal ash that had been removed off-site were unreasonable. (Tr. Vol. 18, pp. 156-60.)

Following the filing of rebuttal testimony by DEP witness Kerin and updated discovery responses from DEP, witnesses Garrett and Moore revised their testimony to indicate that while they no longer took exception with the quantities of coal ash that had been removed from the 1982 Basin at Asheville to accommodate construction of the combined cycle facility, they took exception to (a) the schedule on which DEP removed the coal ash, which resulted in the unnecessary double-handling of some coal ash on site; (b) DEP's decision to transport excavated coal ash to the Waste Management landfill in Homer, Georgia, rather than transporting all of the excavated coal ash to a DEP- or DEC-owned facility, such as the DEC-owned Cliffside landfill; and (c) the per-ton/mile rates paid by DEP to Charah to transport the material from the Asheville site to Cliffside. Witnesses Garrett and Moore instead contended that a reasonable calculation for coal ash transporting costs should be based on the per-ton/mile rates calculated from the Waste Management Contract, but utilizing the shorter transporting distance and lower tipping or placement fee associated with the Cliffside landfill. In total, their proposed disallowance related to the Asheville facility totaled $29.3 million. (Tr. Vol. 18, pp. 173-76.)

Public Staff witnesses Lucas, Garrett, and Moore recommended disallowances of particular coal ash costs. In addition, witnesses Lucas and Maness proposed an "equitable sharing" of the remaining coal ash costs.

6. Public Staff Witnesses Lucas' and Maness' Equitable Sharing And Coal Ash Adjustments Testimony

Witness Lucas 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. This is essentially the approach recommended by DEP, minus costs listed in its federal criminal plea agreement as being non-recoverable in rate proceedings. The second option is to disallow recovery of costs to comply with CAMA on the grounds that CAMA is the direct consequence of imprudent Duke Energy environmental violations. This is essentially the approach recommended by CUCA and the Attorney General witnesses. 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. Under this approach, which the Public Staff advocates, disallowances would be based on the costs to remediate environmental violations rather than the costs flowing from CAMA compliance. (Tr. Vol. 18, pp. 270-71)

However, witness Lucas encountered "complicating factors" that led him to modify his preferred regulatory treatment. (Tr. Vol. 18, pp. 271-73) He observed that while some environmental violations are clearly due to Company negligence, others fall into a gray zone where they are neither plainly imprudent nor plainly reasonable. For instance, decisions to place coal ash in unlined impoundments could have been reasonable based on what DEP knew or should have known at the time the basins were constructed some decades in the past. At the same time, it can be unreasonable to impose on ratepayers the costs incurred because those impoundments leaked coal ash constituents and contaminated groundwater outside the compliance boundaries, in violation of state environmental laws and regulations. He also stated that the costs of many environmental violations would be too speculative to determine, as they involve estimations based on scenarios that did not occur (preventing violations through basin construction or modification some decades earlier, or remedying violations if there had been no CAMA).

Due to the complicating factors, witness Lucas offered what he classified as a more practical approach, proposing to exclude the following coal ash costs from recovery in rates:

(1) DEP litigation costs and settlement payments in cases where there are environmental violations;

(2) costs to remedy environmental violations where the costs exceed what CAMA would have required in the absence of environmental violations;

(3) costs required to be excluded under the probation conditions of the federal plea agreement;

(4) the recommended disallowances from 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. 18, pp. 274-75.)

According to witness Lucas, DEP had stated that it had excluded all costs required to be excluded under the probation conditions of the federal plea agreement. (Tr. Vol. 18, p. 281) Thus, the regulatory treatment of those costs is not in dispute. The remaining areas listed by witness Lucas include litigation and settlement payments in cases of environmental violations. In this category, he recommended exclusion of $88,000 (total system, not just NC retail as shown in Peedin Exhibit 1, Schedule 3-1(n), line 1, $53,328-North Carolina retail) of test year outside legal fees for litigation of a penalty assessment brought by the North Carolina DEQ and a Clean Water Act lawsuit brought by citizen clients (environmental organizations) of SELC, both in connection with coal ash contamination from DEP's Sutton plant. (Tr. Vol. 18, p. 277)

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 Lucas identified, to date, $6,693,390 (NC retail) incurred from January 1, 2015, to August 31, 2017, for extraction wells and treatment of groundwater pursuant to the settlement agreement between DEQ and DEP in the Sutton penalty assessment case. He took the position that these costs would not have been incurred but for unlawful contamination of groundwater by DEP coal ash basins, and that these costs are over and above the lowest reasonable costs of CAMA compliance in the absence of violations. He noted that there could be additional costs in this category in the future. (Tr. Vol. 18, pp. 278-80)

The final category for disallowance is based on an "equitable sharing" of all coal ash-related costs not otherwise disallowed. Witness Lucas referred to witness Maness' testimony for a description of how the equitable sharing should be implemented and the reasons for it. Witness Lucas further opined that "[a]n 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." In this regard, he noted the nature and extent of coal ash environmental problems addressed in the federal criminal plea agreement, violations of NPDES permits, dam safety deficiencies, and numerous groundwater exceedances. He added that the sheer number of legal actions against DEP for coal ash environmental violations is suggestive of the extent of the problem. Witness Lucas asserted that DEP non-compliance with NPDES permits and state groundwater rules would in 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. Based on DEP's culpability for environmental violations, witness Lucas 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. 18, pp. 282-85)

In supplemental testimony, witness Lucas made some corrections to his initial testimony, and submitted Revised Lucas Exhibits 5 and 6. The revisions to Exhibit 5 corrected - and lowered - the number of NPDES permit violations he found, and further noted that the number of NPDES violations did not include unauthorized discharges (i.e., seeps) that are violations of G.S. 143-215.1. The revisions to Exhibit 6 identify which groundwater exceedances are violations of environmental regulations, and which have yet to be determined as violations versus natural background levels. (Tr. Vol. 18, pp. 289-90)

Public Staff Witness Maness proposed seven adjustments with respect to coal ash costs. (Tr. Vol. 18, pp. 298-99.) His adjustments for implementing witnesses Garrett and Moore's recommendations, allocation factors, addition of return on deferred coal ash expenditures from September 2017 through January 2018, and use of a mid-month cash flow convention are covered elsewhere in this Order. Witness Maness noted that the Public Staff did not oppose the Company's request in Docket No. E-2, Sub 1103, to defer coal ash costs that had been recorded as AROs into a regulatory asset for regulatory accounting purposes. He recommended that coal ash costs incurred from January 2015 through August 2017 be allowed as a deferral and that the costs be amortized over a 28-year period. He revised the amortization period to 26 years in his supplemental testimony, based on the cost of capital in the Stipulation between DEP and the Public Staff. (Tr. 18, pp. 336) He also proposed that there be no return allowed on the unamortized balance of the deferred costs. The purpose of the 26-year amortization period in conjunction with no return on the unamortized balance is to create a 50%-50% sharing of the deferred coal ash costs between ratepayers and shareholders.

Among the adjustments recommended by witness Maness was the calculation of a return on deferred coal ash expenditures between January 1, 2015, and January 31, 2018, using a mid-month cash flow convention, rather than the beginning-of-month convention used by the Company. Witness Maness testified that the Company had used a return calculation methodology that accrued a return for each month assuming that all cash flows during the month occurred at the very beginning of the month. Because he felt this assumption to be unrealistic, he made an adjustment to instead use a mid-month cash flow assumption, which essentially treats the cash flows in each month as being experienced throughout the month. (Tr. Vol. 18, p. 308)

Additionally, witness Maness added a return on deferred coal ash expenditures from September 2017 through January 2018, to bring the total balance up to the expected effective date of the rates approved in this proceeding. He testified that the Company had updated its proposed balance of deferred coal ash management costs, with an accrued return, through August 2017. However, the rates in this proceeding are not expected to go into effect until February 1, 2018. Therefore, in order to capture all of the costs, including return, related to the January 2015 - August 2017 underlying coal ash costs, he added the return accumulated on the principal amount through January 2018. (Tr. Vol. 18, p. 307)

Witness Maness recommended three major[17] adjustments to the amount of coal ash management costs subject to deferral. (Tr. 18, pp. 304-05) First is the removal of $80.5 million on a system basis, pursuant to witnesses Garrett and Moore's recommendation related to unnecessary costs for removal of coal ash from the Sutton plant to the Brickhaven site. Second is the removal of $45.6 million on a system basis, pursuant to witnesses Garrett and Moore's recommendation related to unreasonable costs for coal ash processing at the Asheville plant. This amount was reduced to approximately $29 million in Public Staff supplemental testimony. (Tr. 18, p 335) Third is the removal of $6.7 million on a system basis, pursuant to the Lucas recommendation related to costs for extraction wells and treatment of contaminated groundwater. In addition, witness Maness noted that recovery of certain expenditures incurred in the 2015 and 2016 timeframe should be provisional because, as noted in the testimony of witness Lucas, the reasonableness of those expenditures is subject to pending legal determinations. (Tr. Vol. 18, p. 303) For all the foregoing adjustments, witness Maness was implementing, for accounting purposes, the recommendations sponsored by other Public Staff witnesses.

For the "equitable sharing" adjustment, witness Maness provided the substantive support for the recommendation, in addition to the support provided by witness Lucas. (Tr. Vol. 18, pp. 308-16) He testified that the five-year amortization period proposed by DEP was too short for the magnitude and nature of the Company's coal ash costs. (Tr. Vol. 18, p. 308) He advocated a 26-year amortization period, with no return on the unamortized balance, because the result would create an equal sharing of responsibility for coal ash costs between ratepayers and shareholders. He recommended the 50%-50% equitable sharing for all the January 2015 through August 2017 coal ash costs deferred by the Company, except for costs that were the subject of disallowance recommendations as noted in the preceding paragraph.

Witness Maness provided two reasons for his equitable sharing recommendation. (Tr. Vol. 18, p. 309) First, as addressed in more detail by witness Lucas, "the extent of the Company's failure to prevent environmental contamination from its coal ash impoundments, in violation of state and federal laws, supports ratemaking that leaves a large share of the costs for DEP shareholders to pay." Second, there is ample support in prior Commission orders and case law for equitable sharing: past cases involving costs of abandoned nuclear construction and for environmental cleanup of manufactured gas plant facilities resulted in costs being shared between ratepayers and shareholders.

[17] This amount excludes any fines, penalties and other unrecoverable costs incurred by the Company. (Tr. Vol. 6, p. 122.)

In terms of legal support for his recommendation, witness Maness noted that in State ex rel. Utilities Com. v. Thornburg, 325 N.C. 463, 385 S.E.2d 451 (1989), the North Carolina Supreme Court upheld the equitable sharing of nuclear abandonment costs through an amortization over a period of years with no return on the unamortized balance. A similar result was ordered for environmental costs incurred by Public Service Company of North Carolina, in connection with cleanup of manufactured gas plants, in Docket No. G-5, Sub 327 (1984). (Tr. Vol. 18, pp. 310-13)

Witness Maness sought to distinguish the 2016 DNCP rate case, where the Public Staff did not propose an equitable sharing of coal ash costs and reached a settlement with that utility. (Tr. Vol. 18, pp. 315-16) He stated that the magnitude of costs is one reason for the different recommendation, and the paid to date system costs for coal ash in the DNCP case were only about 19% of the paid-to-date system costs for DEP. He further pointed out that the stipulation in the DNCP case made clear that the amortization of future CCR expenditures would be decided on a case-by-case basis.

Finally, witness Maness recommended that DEP be allowed to defer coal ash management costs incurred after August 31, 2017, into an ongoing regulatory asset/liability. He recommended that DEP be allowed to accrue a return on coal ash costs accumulated in the regulatory asset post-August 2017. The return would be the Company's net of tax rate of return, net of associated accumulated deferred income taxes. Any disallowances, and any equitable sharing through amortization with no return, would be determined in the next DEP general rate case for the coal ash costs deferred to the regulatory asset. Witness Maness opposed the Company's proposal of a "run rate" of approximately $129 million for ongoing rate recovery of estimated future coal ash costs. He testified that the run rate could make future equitable sharing of the costs of coal ash much harder to achieve. He conveyed advice of counsel that any attempt to achieve equitable sharing in the run rate by reducing it to recover only part of the coal ash expenses would be open to legal challenge. (Tr. Vol. 18, pp. 316-18)

7. Company Witnesses – Rebuttal Testimony

Kerin

Company witness Kerin's rebuttal testimony responded to the direct testimony of Public Staff witnesses Garrett and Moore and CUCA witness O'Donnell. Witness Kerin noted that witnesses Garrett and Moore conducted a thorough and principled analysis of the costs that DEP incurred to comply with the CCR Rule and CAMA, and he agreed with the majority of their conclusions. He testified further, however, that based on a complete review of the applicable facts, including several overlooked key facts and sets of information, he opposed witnesses Garrett and Moore's suggested disallowances of the Company's coal ash disposal costs. (Tr. Vol. 20, pp. 30-32, 56.)

First, he disagreed with their conclusion that DEP could have built an on-site landfill at the Sutton site in place of the arrangement that DEP has with Charah, Inc., to transport CCRs to the Brickhaven Mine when DEP first started moving coal ash from the site, and with the associated $80.5 million suggested disallowance. Witness Kerin explained that DEP would have been unable practically and in compliance with CAMA to build an onsite landfill at Sutton under the timeframes witnesses Garrett and Moore suggested. He also maintained that, in his view, the lack of any limitation on the moratorium with regard to the Asheville and Sutton existing basins in the statute indicated the General Assembly's intent that DEP was prohibited from constructing a CCR landfill within the areas formerly used for storage coal ash. He also discussed additional regulatory limitations that existed in 2014 and 2015 regarding the construction of CCR landfills in the footprint of existing CCR surface water impoundments. Witness Kerin also explained how witnesses Garrett and Moore made incorrect assumptions concerning the Company's ability to permit and construct a CCR landfill using a "perfect world" scenario without considering the inherent uncertainty of any type of landfill, especially a CCR landfill, particularly during the regulatory and political environment that existed in 2014. He identified reasons DEP should not have started permitting the design for an on-site landfill at Sutton in June of 2014 as witnesses Garrett and Moore suggest. (Tr. Vol. 20, pp. 32-41, 56.)

Finally, with regard to Sutton, witness Kerin explained why the two landfill liner components that witnesses Garrett and Moore excluded from their hypothetical cost calculation are required for this location and were prudent to include in the new landfill design. (Id. at 50-51.) Witness Kerin testified that the unique location of the newly constructed Sutton landfill, being immediately adjacent to the existing coal ash surface impoundments, required use of the liners to effectively monitor the new landfill. The additional liners are necessary for the new CCR landfill design to be able to distinctly monitor the landfill's performance separate and apart from any influence that the adjacent older coal ash basins may be having, both now and in the future. Otherwise, it would be difficult to discern if the new landfill liner system was operating properly (or leaking), or whether groundwater monitoring wells around the landfill were actually detecting an effect from the adjacent coal ash basins.

Witness Kerin also disagreed with Garrett and Moore's conclusion that DEP could have built an on-site landfill at Asheville site rather than contract with Waste Management, Inc. to transport CCRs to an off-site location and the associated $45.6 million suggested disallowance. He testified that the issues that affected the Company's decisions with regard to Sutton, discussed above, also applied to the Asheville site and would similarly have made an on-site landfill option infeasible. He explained that in addition, while the Company had previously—as early as 2007— researched CCR landfill construction at Asheville, CAMA and the Mountain Energy Act of 2015 changed the technical feasibility of an on-site CCR landfill, giving the short time period to replace the coal-fired generation by 2020, and close both coal ash basins by 2022. (Tr. Vol. 20, pp. 33, 42-44, 56-57.) He also disagreed with the quantity of coal ash excavated and transported off site that Garrett and Moore used in its analysis of Asheville, which does not account for over 500,000 tons of coal ash. He testified that the price per ton for coal ash disposal that DEP paid at the Asheville site, reflected in the all-in blended contract rate DEP had for the initial scope of work, was reasonable, and that with the benefit of experience the Company was able to negotiate a more favorable all-in rate in December

2016. Witness Kerin therefore recommended that, if the Commission does find the initial all-in rate to be excessive, a disallowance of approximately $9.5 million could be justified in lieu of the O&M disallowance of approximately $14 million (which witness Kerin calculated after adjusting for the proper coal ash amount). Witness Kerin noted that witnesses Garrett and Moore received information from DEP in response to multiple questions that asked for coal ash quantities at different times and in different ways. He explained each of the variations in coal ash amounts contained in witnesses Garrett and Moore's Exhibit 5. (Tr. Vol. 20, pp. 44-46, 57.)

Witness Kerin addressed the concerns that Garrett and Moore raised with respect to potential for costs to be imprudent in the future if these certain conditions arise. First, witness Kerin testified that potential fulfillment costs related to the Brickhaven and Colon mines are common practice for contracts that require a contractor to develop some large infrastructure to perform a needed service, and that the fulfillment fee was negotiated to fairly and reasonably in acknowledgement of Charah's risk exposure. Second, witness Kerin noted with regard to future water treatment costs that DEP has increasingly accurate cost estimates for each site as its plans develop, on balance water treatment costs are decreasing, and DEP does not object to the Commission and interested stakeholders tracking these costs as they develop. Third, witness Kerin stated that DEP will seek variances to any deadlines, as applicable, where doing so would be in the best interest of customers, and noted that he reads G.S. 130A-309.215 to mean that DEQ's variance authority applies equally to the closure provisions for H.F. Lee, Cape Fear, and Weatherspoon as to other sites. Finally, witness Kerin noted that DEP is in the later stages of contract negotiation for the sale of processed coal ash and expects to have an executed agreement by March 2018, and the first beneficiation unit that witnesses Garrett and Moore are concerned about will come online in late 2019. (Tr. Vol. 20, pp. 33, 47-50, 57.) Also with regard to beneficiation, he explained that DEP identified the Buck, H.F. Lee, and Cape Fear sites for beneficiation as providing the best economic value for customers while complying with CAMA, and that the Company entered into an agreement for Weatherspoon as well but the cement companies could not take enough coal ash to qualify that site under CAMA. (Id. at 51-52.)

Witness Kerin also testified that CUCA witness O'Donnell's analysis and recommendation of a 75% disallowance of the Company's coal ash costs relies on multiple analytical flaws that are fatal to his conclusion. Specifically, witness Kerin disagreed with witness O'Donnell's conclusion that the national comparison of CCR assets retirement obligation, or ARO, amounts shows that the Company's ARO is overstated by 75%, and enumerated 22 factors that he states witness O'Donnell does not appear to have considered, which witness Kerin explained must be accounted for in order to seriously attempt this type of analysis. Witness Kerin recommended that the Commission consider the reasonableness of the Company's ARO amount on its own merits, based on the facts of this case, and without regard to witness O'Donnell's proposal. (Tr. Vol. 20, pp. 52-55, 58.)

Wright

On rebuttal, Company witness Wright testified to several issues related to the recovery of costs associated with coal ash remediation expenses raised in the testimonies of Public Staff witnesses Lucas and Maness, AGO witness Wittliff, and CUCA witness O'Donnell. He stated that, overall, the theories underlying these witnesses' recommended disallowances of these costs are unfounded, do not justify disallowance, and should be rejected by the Commission. (Tr. Vol. 20, pp. 127-28, 170.)

Witness Wright first disagreed with Public Staff witness Lucas' recommendation to disallow 50% of the Company's remaining coal ash costs after accounting for certain other disallowances that he and Public Staff witnesses Garrett and Moore recommend. Witness Wright stated that this recommendation does not align with the appropriate regulatory standard for denial of cost recovery, including recovery of environmental compliance costs, which he explained is a finding that specifically identified costs are imprudent or unreasonable. He noted that witness Lucas did not find the Company imprudent for most of the coal ash-related cost, nor did witness Lucas find the Company's costs to be unreasonable. Instead, witness Wright explained, witness Lucas asked the Commission to disallow these costs apparently based on the theory that the Company acted poorly in its historical coal ash disposal methods and on speculation of past or future environmental compliance issues. Witness Wright stated that it is not proper for the Commission to deny cost recovery based on speculation of future findings of violation, or to impose a sharing of costs based upon an undefined culpability standard. (Tr. Vol. 20, pp. 128-29, 131-35, 170-71.)

Witness Wright also explained that the proposed sharing of cost is also inconsistent with Commission precedent and with the Public Staff's own position on the recovery of coal ash disposal cost in Dominion's 2016 base rate case. In that case, he recalled, Dominion requested a recovery of CCR Rule compliance costs up to and through 2016. He explained that those expenditures included closure and related costs for the Chesapeake Energy Center, even though a court found past violations of the Clean Water Act at this location. He stated that the Commission concluded that the recovery of these costs, as provided in the stipulation entered into in that case by the Public Staff and Dominion, was just and reasonable. He stated his opinion that the CCR cost recovery methodology applied in the Dominion case was correct and should be applied in the same way for DEP. (Tr. Vol. 20, pp. 135-37, 141-42, 171-72.)

Witness Wright also testified that the Public Staff's suggestion that the Commission's treatment of abandoned nuclear plants supports its proposed cost sharing proposal is not appropriate, because abandoned nuclear plant costs are not comparable to CCR costs. He explained that the Commission has found abandoned nuclear cost not to be used and useful, and thus not eligible for rate-based treatment. In contrast, he noted, the coal plants associated with these costs and the related coal ash disposal facilities have been used and useful in providing low-cost, reliable power to North Carolina customers for more than 70 years, and will continue to be used and useful. He stated that this is consistent with the recent Dominion case, where the

Commission found that CCR repositories were and continue to be used and useful, were therefore not abandoned, and were therefore eligible for recovery through amortization and a return on the unamortized balance, similar to other types of used and useful property. (Tr. Vol. 20, pp. 137-38, 142-44, 172.)

Witness Wright went on to state that the Commission’s treatment of environmental cleanup of manufactured gas plants also does not support the Public Staff’s proposed cost sharing, and referred to his direct testimony that MNG plant costs differ from coal ash disposal costs, both in terms of the time that elapsed between the actual usage of the facility and the environmental-related cost recovery, and in terms of ownership. In addition, he noted that MNG facilities, like abandoned nuclear plants, were found not to be used and useful. He noted further that there is no need to rely on a 23-year-old cost recovery example from a different industry, dealing with assets last used more than 70 years ago, when the best example of the Commission’s treatment of coal ash disposal costs can be found in the Dominion case that was decided one year ago. (Tr. Vol. 20, pp. 138-40, 173.)

Witness Wright also testified that the 28 (26)-year amortization period proposed by the Public Staff is not justified either by their cost sharing theory, or by defining these costs as being extremely large. He explained that adoption of this proposal would undermine the basic cost of recovery principles embodied in North Carolina utility regulation and would subject utilities to an unknowable and ill-defined cost recovery standard. He explained further that it could also result in a perception of the state’s utilities as riskier, leading to higher cost of capital and cost of service. (Tr. Vol. 20, pp. 140-41, 144-45, 173-74.)

Witness Wright disagreed with witnesses that claimed that Duke Energy substantially caused the CCR Rule and CAMA and that, therefore, all costs incurred to comply with these requirements should be disallowed. He referenced his direct testimony that while the timing of CAMA may have been influenced by the Dan River accident, he cannot conclude that the North Carolina legislature would have adopted a different substantive law without Dan River. He noted in addition that there are numerous examples of North Carolina lawmakers and regulators adopting environmental policies, not only specific to this state, but stricter than national or neighboring states' policies. He also noted that state-specific actions to address CCRs have been adopted in a number of jurisdictions. Based on all these factors, he opined that North Carolina likely would have adopted a state-specific CCR regulation regardless of the Dan River accident. (Tr. Vol. 20, pp. 145-50, 174.)

Witness Wright also expressed his opinion that CAMA was not intended to be a punitive law. He noted that CAMA does not contain any punitive limitation on cost recovery except for the provision for certain spills to surface water. He also noted that attempts to further restrict coal ash disposal cost recovery under this law have been tried three times, but in all three cases, amendments or laws to disallow cost recovery were defeated. He stated that the General Assembly has shown that it will, when it wants to, adopt specific cost recovery restrictions with other state environmental laws, as exemplified by the Clean Smokestacks Act. In contrast, he explained, the legislature's affirmative decision not to disallow prudently-incurred costs related to CAMA, and not to adopt subsequent proposals to disallow such costs, indicates that CAMA was not meant to be punitive with regard to cost recovery, but rather intended to leave cost recovery determinations to this Commission's oversight and sound regulatory policy. (Tr. Vol. 20, pp. 151-53, 174 -75.)

With regard to coal ash litigation costs, witness Wright reiterated that DEP has excluded from its recovery request all fines, penalties, and fees related to the Dan River accident. (Tr. Vol. 20, 164-65.) He also opined, however, that witness Lucas' apparent position that all of the Company's costs to defend lawsuits should be disallowed recovery, regardless of whether the Company is ultimately found liable or not, is not supported by precedent or sound regulatory policy. First, the Glendale Water case does not support this theory. In addition, he noted that the Commission has recognized that settlements and litigation defense costs, when reasonable and prudent, are recoverable costs, and that the Commission and the Public Staff have also recognized that settlements are beneficial. He concluded that the Public Staff's apparent position in this case, that, if DEP did not commit violations, it should not settle, is inconsistent, not only with public policy but also with the positions it has previously taken with regard to settlements. With respect to potential settlements of coal ash disposal methods at the Mayo and Roxboro facilities, he noted that this position also leaves the Company in an untenable position, since witness Lucas testifies both that DEP should spend whatever amount is required in order to never have a groundwater issue, and that, if in the course of any settlement as to Mayo and Roxboro, DEP agreed to a coal ash remediation methodology and costs beyond the minimum required by law, those costs should be disallowed, even if that methodology would be more likely to prevent future groundwater issues. (Tr. Vol. 20, pp. 153-61, 175-77.)

Witness Wright also addressed witness Lucas' argument that North Carolina's 2L rule imposes strict liability, such that the Company must take any action, regardless of either cost or industry practices, to avoid or cure a violation of this rule, and his contention that, because water extraction and treatment required under the CCR Rule and CAMA have a curative effect on past alleged 2L violations, the cost of those activities, $6.7 million in this case, are not recoverable. Witness Wright testified that there is no evidence that the 2L rule was intended as strict liability and that, regardless, the standard for cost recovery is reasonableness and prudency, not strict liability. He stated that adoption of the Public Staff's position would effectively require that, with any alleged or potential violation, the utility would be expected to immediately undertake remediation, regardless of the expense, and potentially even nonstandard, experimental environmental compliance projects that could not only be costly, but ineffective. (Tr. Vol. 20, pp. 161-62, 177.)

While witness Wright agreed with witness Lucas that DEP could, in theory, have undertaken coal ash disposal projects above and beyond any legal requirements or industry standards, he noted that those costs would have been subject to high scrutiny, and the Company likely would have been accused of gold-plating. More generally, he explained that it is not appropriate to apply the benefit of hindsight to judge whether expenditures that DEP made under the circumstances known at the time were reasonable. (Tr. Vol. 20, pp. 163-64, 177-78.)

For similar reasons, witness Wright also disagreed with the Public Staff's recommendation of provisional cost recovery for coal ash expenditures prudently incurred from January 2015 through August 2017, based on the argument that the appropriateness of such recovery may depend on the outcome of legal determinations. He noted first that this would appear to be retroactive ratemaking. He also stated that the standard is that the utility makes the best possible decisions on expenditures based on the information available at the time, and determinations of the reasonableness and prudency of these costs should not depend on future outcomes of legal proceedings but what was known or knowable at the time. (Tr. Vol. 20, pp. 165-66, 178.)

Witness Wright testified further that the Commission should reject AGO witness Wittliff's recommendation that DEP only be allowed to recover costs required to comply with the CCR Rule, and not any costs related to CAMA. He noted that witness Wittliff neither quantified the disallowance he recommends, nor offered any regulatory policy or logical support for his position, and stated that his proposals are unsupported by good regulatory policy, precedent, or logic. (Tr. Vol. 20, pp. 167-68, 178-79.)

Finally, witness Wright opined that the Commission should reject CUCA witness O'Donnell's recommendation that 75% of the Company's environmental compliance costs should be disallowed based on a comparison of the alleged national asset retirement obligations, or ARO, amounts relating to CCRs. He stated further that the Commission should reject any disallowance, especially one as substantial as the amount witness O'Donnell recommends, that is not based on facts and evidence that have been proven and verified as mathematically correct and substantially significant, and that to do otherwise would constitute poor regulatory policy and would be arbitrary. (Id. at 168-69, 179.)

At the hearing, witness Wright explained during cross-examination by counsel for the Sierra Club the decision tree that the Commission uses to determine whether costs are recoverable and how that recovery will occur. He explained that the first question is whether the costs were reasonable and prudent in providing service to ratepayers, and, if so, the next question is whether they were used and useful, and, if used and useful, the last stage is to consider what outcome would be fair and equitable. He explained further that it is at the last stage where the Commission has leeway to consider different rate designs to achieve a fair and equitable result. He stated that the Public Staff's equitable sharing proposal does not follow this decision tree, but attempts to impose a splitting of costs with no consideration for reasonableness and prudence, etc. He noted that that is a cost recovery approach that he has not seen in his experience. (Tr. Vol. 20, pp. 186-88.)

Witness Wright testified in response to questions by counsel for the Public Staff that the fact that DEP has an exceedance or even a violation is not indicative or necessarily tied to the recoverability of costs DEP is seeking in this case. He explained that if DEP has a violation and admitted wrongdoing, or an adjudicated proceeding determined there was wrongdoing, then those costs or fines should not be recovered. He testified that that is different from DEP's having to now comply with new standards; in terms of costs associated with new obligations, he considers those long-term compliance costs. (Id. at 209-11.) In response to cross-examination regarding this case as compared to the 2016 Dominion case, witness Wright clarified that he believes the run rate that DEP has proposed in this case is reasonable. (Id. at 212-13.) Witness Wright also clarified that references to the Dan River spill in the final CCR Rule indicate that the EPA cited that event as evidence that the rule was needed, not as a factor that changed the substance of the rule itself. He testified further that references to Dan River in the initial version of CAMA support his position that Dan River influenced the timing but not the substance of that law. (Tr. Vol. 21, pp. 14-17.) He also noted that, while the CCR Rule does not require mandatory excavation, based on his discussions with witness Kerin, witness Wright believes that site studies and engineering analysis that would have been done in support of CCR led to the same closure methodologies that CAMA requires. (Id. at 18-19.) Finally, witness Wright clarified that the Public Staff's position, that DEP should have spent any amount required to prevent any groundwater contamination years ago and risk disallowance of those costs, but also that DEP should not be able to recover the costs it has now prudently incurred to comply with new laws and regulations, is inconsistent. (Id. at 33-35.)

Wells

Company witness Wells testified that DEP's compliance record with respect to NPDES permits has been exemplary. He stated that the Company has consistently complied with the terms of its NPDES permits over the years, and that, of well over 70,000 data points, it has had fewer than 200 permit violations, which is less than one half of 1% at all seven of its facilities in the last 10 years. Specifically with regard to Asheville, Cape Fear, H.F. Lee, Sutton, Roxboro, and Weatherspoon plants, witness Wells noted that DEP has had no more than 20 NPDES permit exceedances during this time frame. He stated that, when compliance issues have arisen at individual plants, DEP has addressed those issues with regulators. (Id. at 62-63, 88-89.)

Witness Wells continued that, in his direct testimony and original Exhibit 5, witness Lucas asserted that DEP has 2,172 NPDES permit violations over the past 10 years. He noted that witness Lucas included in that total groundwater data associated with reported monitored exceedances of groundwater quality standards. Witness Wells emphasized, however, that groundwater data are not permit violations. Rather, he explained, these permits require the Company to monitor groundwater in compliance with a monitoring plan and report the data to the DEQ. He explained that a monitored exceedance of a groundwater standard is not a permit violation, and DEQ has never issued DEP a notice of violation identifying groundwater data as the basis of a permit exceedance. He concluded that the Public Staff has conflated these two concepts. (Id. at 64-66, 74-76, 89.)

Witness Wells explained further that exceedances of groundwater standards and the existence of seeps in the vicinity of the Company's coal ash basins do not indicate mismanagement or poor compliance programs. He stated that the existence of groundwater exceedances at or beyond the compliance boundaries at DEP sites is rather a function of where these sites are on the timeline of groundwater assessment and corrective action under modern laws that have changed the way unlined basins are viewed. He testified that the Company's decision to use unlined basins to treat coal ash transport water was reasonable and consistent with the approach employed across the power industry at the time that the basins were built. He noted that each DEP site had been properly and legally operating an unlined basin for at least a decade before the adoption of any regulatory requirements related to groundwater corrective action. He noted further that as requirements changed over time, DEP has taken every action required by DEQ's groundwater rules, and later by the CAMA and the CCR Rule, to address groundwater impacts as they have been identified. (Id. at 66, 76-77, 91-92.)

For similar reasons, witness Wells also disagreed with the Public Staff's suggestion that any exceedance or violation of water quality regulations, no matter how minor or how long ago, leads to the denial of cost recovery for any activity that acts to "cure" the impacts of the violation. In addition to reiterating that not all exceedances of the 2L standards amount to a violation that requires corrective action under the 2L rules, witness Wells stated that even when an exceedance requires corrective action, the groundwater rules do not treat the exceedance the same way as, for example, the Clean Water Act treats an exceedance of an NPDES permit limit. When the latter is violated, he explained, the permittee is immediately subject to an NOV and penalty, and must ensure the next discharge complies with the permit limit or risks a new NOV and escalating penalty. He stated that in those circumstances, it would be reasonable to say that allowing the violation to continue without addressing it is mismanagement. He contrasted this with groundwater standards, under which an exceedance does not immediately result in an NOV and penalty. Instead, he explained the owner/operator must report the exceedance and work with the DEQ to determine whether it was due to permitted activity, assess the extent of the exceedance, and undertake corrective action. Any newly measured exceedances do not require a further site assessment and do not result in additional or escalating penalties, but are actually expected as additional assessment prior to corrective action is conducted. He testified that the 2L rules' correction action provisions are deliberately designed around the idea that older facilities, built before liners were a regulatory obligation, were likely to have associated groundwater impacts, that such impacts were not the result of regulatory noncompliance, and that they should be addressed in a measured process. He concluded that compliance with this process is not mismanagement and should not be held against DEP with respect to cost recovery. (Tr. Vol. 21, pp. 79-80.)

Witness Wells noted at the hearing that, after he filed his rebuttal testimony, witness Lucas filed supplemental testimony that acknowledged the distinction between exceedances and violations. Witness Wells noted that, in his supplemental testimony, witness Lucas admitted that most of the instances of what he had called NPDES permit violations in his original Exhibit 5 are not NPDES permit violations, and submitted a

Revised Exhibit 5 that removes groundwater exceedances from the total number of NPDES permit violations. Witness Wells stated that this change reduced the total number of witness Lucas' alleged permit violations to 458, a reduction of about 79%. (Id. at 89-90.)

Witness Wells continued that, of the remaining 458 allegations, 199 are listed as occurring at the Mayo plant, which the Company acted quickly to address by installing the Zero Liquid Discharge system. He noted that the other 255 alleged violations listed in witness Lucas' revised Exhibit 5 are new alleged failure to monitor events. As with the original Lucas Exhibit 5, he explained, this number of failure to monitor violations is inaccurate and significantly overstated. He stated that the vast majority of these alleged violations were reviewed by DEQ staff at the time of the events and determined not to be violations. He also stated that the documents relied on by witness Lucas clearly indicate where DEQ made that determination that no action was warranted, but that witness Lucas did not fully incorporate that information into his evaluation. He concluded that removing the Mayo specific events from witness Lucas' corrected 458 number leaves only four permit exceedance violations for the other six DEP sites in the last 10 years, according to witness Lucas' revised exhibit. (Id. at 90.)

Witness Wells noted further that after he filed his rebuttal testimony, witness Lucas revised his Exhibit 6 to also distinguish between groundwater exceedances and groundwater violations. Witness Wells explained that only exceedances beyond the compliance boundary and above background concentrations required further action, and that DEQ is currently in the process of finalizing background levels for the DEP basins. Witness Wells pointed out that witness Lucas appeared to have removed background wells and invalid samples from his original Exhibit 6, and that the Revised Exhibit 6 reduced the number of alleged violations for 12 of the 23 parameters, reducing the total approximately 65%. He pointed out also, however, that these changes still do not take into account consideration of the fact that CAMA requires comprehensive site assessments of groundwater, which increased the number of monitoring wells and the number of samples to accurately characterize the site. (Id. at 21.)

In his rebuttal, witness Wells disagreed with witness Lucas' apparent contention that DEP should have moved well ahead of accepted science, regulatory requirements, and industry practice and should have begun taking measures to prevent any and all groundwater quality issues without regard to the cost of those measures or whether sufficient and proven technology existed at the time to address the conditions at the site. He opposed the suggestion that DEP only engaged in comprehensive groundwater monitoring and remediation when forced to do so by CAMA and other developments. He explained that the Company began monitoring groundwater at Sutton in 1984, Roxboro in 1987, Weatherspoon in 1990, and the remaining sites in or around 2006. He noted that, in 2011, DEQ prescribed a process to be undertaken by DEQ and utilities upon the identification of a groundwater exceedance near a coal ash pond, which included performance of an assessment to determine the cause of the exceedance and, as necessary, develop a Corrective Action Plan consistent with North Carolina groundwater rules. He stated that under that process, only after a utility failed to undertake corrective action when directed to do so would DEQ consider pursuing enforcement. He stated that at all times DEP has cooperated with the department in this corrective action process and continues to do so to this day. (Tr. Vol. 21, pp. 67-73, 92-93.)

Witness Wells also testified that North Carolina's groundwater laws were not intended, as witness Lucas contends, to be punitive. He explained that, for historical sites such as those at issue in this case, this state's groundwater regulations and the DEQ's practices and policies are focused on environmental protection rather than culpability, that the required corrective action is based upon science and not an assessment of wrongdoing. He stated that, in evaluating Corrective Action Plans, DEQ considers numerous factors, including the extent of any threat to human health, impact on the environment, available technology, potential for natural degradation of the contaminants, and cost and benefits of restoration. He cited the example that the groundwater exceedances at the Sutton site were not the result of mismanagement. He stated that the extraction and treatment costs witness Lucas recommends for disallowance relate to work that DEP agreed to accelerate and would be required in the normal course as a part of the groundwater corrective action under the CCR Rule and CAMA. (Id. at 73-74, 93-94.)

At the hearing, in response to questions from counsel for the Sierra Club, witness Wells characterized the 2L rule as a process that is set up to establish groundwater standards around the basins, that recognizes that there is potential for impact to groundwater beneath the basins, and that established compliance boundaries 500 feet from the waste boundaries. He explained that the 2L rule structure is that upon detection of a contaminant above a standard or above background at the compliance boundary, one proceeds to the next step, assessment and, depending on the assessment, proceed to corrective action. He noted that the rule is not, particularly with historical, lawfully designed sites, intended to be punitive. He stated that noncompliance arises if the company fails to take action upon detection, fails to follow the process set forth in 2L. He testified that the policy statement contained at Section 2L.0103 is consistent with that purpose. (Tr. Vol. 21, pp. 102-04.) In response to further questioning, witness Wells clarified that groundwater corrective action plans are conducted in parallel with basin closures, and that the groundwater corrective action plans will consider the various methods of closure to understand those impacts to groundwater. He also noted that, regardless of the closure method that DEP selects, groundwater can always be addressed separately from the closure method. (Id. at 110.)

In his rebuttal, witness Wells also disagreed with witness Lucas that the amount of litigation regarding the Company's coal ash basins suggests that the Company was imprudent in managing coal ash. He opined that the amount of litigation has been driven by nongovernmental organizations that have been pressing for complete excavation of coal ash from all basins across the Southeast. He stated that DEP has appropriately been opposed to this, arguing instead that final closure methods should be dictated by site-specific characteristics based upon science, regulatory policy, and the best interest of our customers. He noted that DEP has resolved such litigation where CAMA made the suit moot and where science and engineering supported closure by excavation, and that the Company continues to vigorously litigate cases where other closure methods are more or equally protective of the environment at less cost. (Id. at 77-78, 94.)

Witness Wells' rebuttal also addressed seeps. He explained that all earthen impoundments seep, and that DEQ's dam safety regulations acknowledge this. He stated that EPA first directed permitting authorities to address seeps in 2010, and at that time, the Company engaged DEQ to determine the appropriate approach to address seeps and began including them in permit applications. He noted that DEQ did not consider seeps to have a significant environmental impact. He also noted that EPA and DEQ did not appear to agree on the appropriate approach to address seeps. He stated that, absent the CCR Rule or CAMA, the existence of seeps in a basin would not on its own automatically trigger basin closure and should not, therefore, impact the Company's ability to recover its CCR environmental compliance costs. He testified that, although closing basins would be one way to address seeps, it would be the most drastic of several possible remedies, and both EPA and DEQ have stated that seeps can be addressed by permitting or rerouting, among other options. (Id. at 81-85, 95.)

Finally, witness Wells disagreed with witness Lucas' suggestion that DEP caused the creation and adoption of the CCR Rule. He testified that the environmental regulatory regime is an ever-evolving body of law, and the EPA engaged in more than two decades of studies before it finally issued a proposed CCR Rule in 2010. Through this process, he noted, the EPA identified 150 cases in over 20 states involving over 25 utilities and government facilities that involved groundwater damage with at least a potential link to coal ash, but determined that immediately closing basins, which would require shutting down operating coal plants, would be more harmful than taking a measured approach. (Id. at 85-87, 95-96.)

At the hearing, in response to questioning by counsel for the AGO and Public Staff, witness Wells explained that previous reports, analyses, and communications regarding how the Company's coal ash basins will be managed indicate that prior to CAMA and CCR Rule the regulatory approach and understanding of groundwater associated with coal ash basins was maturing. For example, he stated that a 2004 report analyzing long term coal ash strategy for the Sutton plant specifically appeared to have been evaluating alternatives for that location given the evolving regulatory scrutiny of coal ash basins and how the Company would manage that and any environmental impacts going forward. Similarly with respect to a 2014 executive order from the governor of North Carolina, which stated that the issue of coal ash storage had not been adequately addressed in the state for decades, he testified to his belief that this statement was not a reflect of any mismanagement or acts or omissions on Duke's part, but of an understanding of the maturity and evolving views of coal ash management throughout the country, and of a recognition that historical designs and management practices needed updating. He also testified that the Company's guilty plea in the federal criminal action was not a reflection of mismanagement of coal ash by the Company as a whole. He acknowledged that the Company took responsibility for the allegations, cooperated with government, and based on the facts at that time at those sites, agreed the Company did not meet its own standards. (See Tr. Vol. 21, pp. 123-25, 145-46.) Witness Wells also noted that the full context of the depositions with DEQ personnel demonstrates the normal cooperative process between the agency and the Company, in which DEQ has final authority. (Id. at 136-39.) In response to questioning from the Commission, witness Wells confirmed that DEP began voluntary monitoring of groundwater in 2006 at facilities where monitoring was not already required. He explained further that the Company was a member of the industry group (Utility Solid Waste Advisory Group) that worked with EPA to address emerging issues, and that as part of that group it agreed to implement groundwater monitoring at these sites and share the results with the EPA. He agreed that the Company considered it reasonable to begin the monitoring at that time even though it was not required, as part of the continued evolution and maturation of the understanding in the industry of environmental impacts of the basins. (Tr. Vol. 22, pp. 30-32.)

In response to questions by the Chairman, witness Wells testified that the testimony and evidence he observed during the hearing confirmed and strengthened his support for the positions contained in his pre-filed testimony. He explained that permit compliance in particular is a very complex, challenging issue, and that the Company's compliance record and his experience with respect to NPDES permit compliance has been outstanding. He noted that out of 70,000 data points on this subject, the evidence shows approximately 20 violations. He noted further to put that number in context that one of those violations was, out of 10 years of sampling at Asheville, one sample exceed the oil and grease limits, at 15.7 ppm vs. 15.0. And that a duplicate sample showed a level of less than 5, but could not be used due to its timing expiring. He explained that this example puts into perspective the violations that have been framed inaccurately during the proceeding. He also noted the response to his rebuttal that suggested that the Company missed sampling, and clarified that all of the 117 missed sampling events at H. F. Lee contained in witness Lucas' revised exhibits were incorrect, that in fact there were no missed sampling events. He explained that, for example, there was a flood event where the plant was in shutdown and there was no flow, and that he could provide similar explanations for each variance event. He noted that the record had so far not been clear on these points. (Tr. Vol. 22, pp. 43-45.)

Commission Determinations

The Commission has reviewed with care the evidence on the issue of CCR remediation cost recovery and the arguments and contentions of the parties. The Commission cannot agree with the ultimate positions of any party. The Commission rejects full recovery advocated by DEP, extensive disallowances advocated by others and the "equitable sharing" concept advocated by the Public Staff.

The Public Staff's Specific Cost Disallowance Proposals

The Commission must undertake a detailed analysis before any costs can be disallowed on the basis of findings of imprudence alone. 1988 DEP Rate Order at 15. The Public Staff undertook such an analysis of the Company's coal ash costs, and came up with three discrete and specific proposed disallowances. Two were presented through witness Lucas: first, $88,000 of legal expense associated with two litigation matters regarding alleged environmental violations, one brought by private parties and one brought by NC DEQ, and, second, approximately $6.7 million in groundwater extraction and treatment costs resulting from a settlement in the DEQ case, which witness Lucas attributes to past violations by the Company of North Carolina's groundwater standards (the "2L Standards"). Third, Public Staff witnesses Garrett and Moore recommended a disallowance totaling $109.8 million relating to the cost of off-site transportation and disposal of coal ash from the Sutton and Asheville Plants, on the grounds that prudence dictated that the coal ash be disposed of in on-site facilities to be constructed rather than being hauled off-site.

Lucas: Alleged Environmental "Violations"

The Public Staff, through witness Lucas, asserts that the rationale for disallowance of the litigation expense and groundwater costs is that these costs flow from "violations" of the law. (Tr. Vol. 18, p. 275.) Witness Lucas cites the Glendale Water case (State ex rel. Utils. Comm'n v. Public Staff, 317 N.C. 26, 343 S.E.2d 898 (1986)) for the proposition that the legal expense should be excluded. (Id.) In that case, the North Carolina Supreme Court held that legal expense associated with a penalty proceeding in which the utility had been found to have violated the law should be excluded. (Id.) Although he does not say so explicitly, the same rationale would apply to witness Lucas's exclusion of the groundwater extraction and treatment costs incurred in a settlement context.

The distinction between the Public Staff recommended adjustment and Glendale Water is that there is no finding in the litigation brought against the Company, or admission by the Company in that litigation, that any "violation" actually occurred. Witness Lucas's testimony that the legal expense and the groundwater treatment cost resulted from any "violation" is based on the "size of the settlements." (Tr. Vol. 18, p. 386.) The settlements referenced by witness Lucas amount in total to $7.25 million – $1.25 million to settle the private litigation, and $6 million to settle the DEQ litigation.[18] Witness Lucas elaborated: "I made my [disallowance] decision on just the large amount – the millions of dollars of settlements [that] were paid by the Company, and I don't believe that the Company would have made those large settlement sums unless it believed it did have some fault." (Id. at 386-37.)

The Commission determines that the facts in this case and Glendale Water are distinguishable. Disputed matters are settled frequently, for many reasons other than settling parties' underlying view of the merits of the dispute. In this case, for example, the Company and the Public Staff have entered into a Partial Settlement which includes

[18] Witness Lucas acknowledges that the settlement amount is not included in the Company's cost of service, and that the Company is not seeking to recover it in rates. (Tr. Vol. 18, p. 277.)

an ROE of 9.9% (versus the Public Staff's recommendation of 9.2%), and a capital structure of 52% equity and 48% debt (versus the Public Staff's recommendation of 50/50). This proposed settlement results in millions of dollars paid by customers over and above the Public Staff's pre-settlement position, but that does not mean that the Public Staff has disavowed its pre-settlement position.

The Commission determines that entering into a settlement does not equate to an admission of guilt or wrongdoing. The North Carolina Rules of Evidence prohibit parties from using the existence of a settlement as evidence of liability.[19] The Public Staff has defended as good regulatory policy the encouraging of reasonable and prudent settlements. In 2016, NC WARN filed a Petition for Rulemaking seeking to require settlements between the Public Staff and utilities to be made open to the public. (Tr. Vol. 20, p. 157); See also In the Matter of Rulemaking Proceeding to Consider Proposed Rule Establishing Procedures for Settlements and Stipulated Agreements, Order Declining to Adopt Proposed Settlement Rules, Docket No. M-100, Sub 145 (Mar.1, 2017) ("Settlements Order"). The Public Staff opposed NC WARN's petition, arguing that public policy favors settlements:

> [T]he Public Staff submits that settlements promote the informal exchange of ideas and information among the parties, the elimination of insignificant or noncontroversial issues ahead of an evidentiary hearing, informed decision making and the efficient administration of justice, especially in the complex matters that are typically before the Commission. Moreover, settlements result in savings to consumers by reducing litigation expenses that would otherwise be recoverable by utilities as a component of the cost of providing utility service.

(Tr. Vol. 20, pp. 157-158; Settlements Order at 3.)

Further, the Public Staff cited to North Carolina case law "touting the benefits of settlements" in business litigation. (Tr. Vol. 20, p. 158; Settlements Order at 3 (citing Knight Pub. Co., Inc. v. Chase Manhattan Bank, N.A., 131 N.C. App. 257, 262 (1998) (Knight)). The Public Staff relied on the principle articulated in Knight that North Carolina "law favors the avoidance of litigation," and a compromise made in good faith "will be sustained as not only based upon sufficient consideration but upon the highest consideration of public policy as well." (Tr. Vol. 20, p. 158 (quoting Knight, 131 N.C. App. at 262 (emphasis added) (internal quotations omitted)). The Commission determines that it should not approve a disincentive to settle pending or future lawsuits.

[19] N.C. R. Evid. 408 ("Evidence of (1) furnishing or offering or promising to furnish, or (2) accepting or offering or promising to accept, a valuable consideration in compromising or attempting to compromise a claim which was disputed as to either validity or amount, is not admissible to prove liability for or invalidity of the claim or its amount. Evidence of conduct or evidence of statements made in compromise negotiations is likewise not admissible.").

These considerations likewise apply to the groundwater treatment costs witness Lucas seeks to disallow, which are the subject of the settlement agreement between DEQ and the Company (DEQ Settlement Agreement). (See Public Staff Wright Rebuttal Cross- Examination Ex. 7.)[20] The DEQ Settlement Agreement references in its recitals a DEQ "Policy for Compliance Evaluations" promulgated in 2011. It appears from the recitals and their description of that Policy that questions as to whether violations of the state's groundwater standards have occurred. (See DEQ Settlement Agreement, at 3, 4-5.) The recitals also indicate, with the passage of CAMA, that the Company would be required to close its coal ash basins, and that CAMA "dictate[d], in detail a procedure for assessing, monitoring and, where appropriate, remediating groundwater quality in areas around coal ash impoundments in North Carolina …." (Id. at 3-4.) Further, in the recitals the DEQ acknowledged that the CAMA requirements were "designed to address, and will address, the assessment and corrective action" associated with alleged groundwater contamination. Because CAMA would require the Company to implement certain action, the Commission determines that it was reasonable for the parties to settle irrespective of whether the Company had committed violations of 2L Standards. Had the Company continued to litigate the matter in this circumstance, its actions may have been deemed by the Public Staff and this Commission to be imprudent, with a disallowance of the legal costs incurred in connection with continued litigation disallowed.

Here, the testimony of Company witness Wells is instructive. Witness Wells successfully countered witness Lucas's notion that the Company had experienced 2,172 NPDES permit violations over the past 10 years (See original Lucas Exhibit 5). Witness Lucas reduced the number of the alleged violations in his Supplemental Testimony to merely 458 violations. (Tr. Vol. 16, p. 369). Witness Wells testified that witness Lucas included in that total groundwater violations data associated with reported monitored exceedances of groundwater quality standards. Witness Wells testified that groundwater data are not permit violations. Rather, he explained, these permits require the Company to monitor groundwater in compliance with a monitoring plan and report the data to the DEQ. He explained that a monitored exceedance of a groundwater standard is not a permit violation, and that DEQ has never issued DEP a notice of violation identifying groundwater data as the basis of a permit exceedance. He concluded that the Public Staff has conflated these two concepts. (Tr. Vol. 21, pp. 64-66, 74-76, 89.) The Commission notes however that witness Wells' testimony here appears inconsistent with the Company's guilty pleas in federal criminal court.

Witness Wells argued that DEP's compliance record with respect to NPDES permits has been exemplary. He stated that the Company has consistently complied with the terms of its NPDES permits over the years, and that, of well over 70,000 data points, it has had fewer than 200 permit violations, which is less than one half of 1% at all seven of its facilities in the last 10 years. Specifically with regard to Asheville, Cape

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[20] However, they do not apply to DEP's representations in the federal district criminal court proceeding where no settlement and where admissions of liability were made.

Fear, H.F. Lee, Sutton, Roxboro, and Weatherspoon plants, witness Wells noted that DEP has had no more than 20 NPDES permit exceedances during this time frame.[21] He stated that, when compliance issues have arisen at individual plants, DEP has addressed those issues with regulators. (Id. at 62-63, 88-89.) Witness Wells argued further that impacts to the groundwater surrounding coal ash basins are an expected result of using unlined basins and are not the result of any mismanagement. At the time they were built – between 1956 and 1985 – unlined basins were consistent with the industry standard and considered by the EPA to be the best available control technology. (Tr. Vol. 21, p. 67.) In 1984, when the predecessor to DEQ promulgated the corrective action provisions of the 2L Standards, it acknowledged that the groundwater surrounding many existing permitted facilities was likely to exhibit some exceedances of the 2L Standards through no fault of the facility owner. (Id.) As stated above, the Commission deems this testimony instructive.

Witness Wells also disagreed with the Public Staff's suggestion that any exceedance or violation of water quality regulations, no matter how minor or how long ago, leads to the denial of cost recovery for any activity that acts to "cure" the impacts of the violation. In addition to reiterating that not all exceedances of the 2L standards amount to a violation that requires corrective action under the 2L rules, witness Wells stated that even when an exceedance requires corrective action, the groundwater rules do not treat the exceedance the same way as, for example, the Clean Water Act treats an exceedance of an NPDES permit limit. When the latter is violated, he explained, the permittee is immediately subject to an NOV and penalty, and must ensure the next discharge complies with the permit limit or risks a new NOV and escalating penalty. He stated that, in those circumstances, it would be reasonable to say that allowing the violation to continue without addressing it is mismanagement.

He contrasted this process with groundwater standards, under which an exceedance does not immediately result in an NOV and penalty. Instead, he explained, the owner/operator must report the exceedance and work with the DEQ to determine whether it was due to permitted activity, assess the extent of the exceedance, and undertake corrective action. Any newly measured exceedances do not require a further site assessment and do not result in additional or escalating penalties, but are actually expected as additional assessment prior to a requirement to take corrective action. He testified that the 2L rules' correction action provisions are designed around the idea that older facilities, built before liners were a regulatory obligation, were likely to have associated groundwater impacts, that such impacts were not the result of regulatory noncompliance, and that they should be addressed in a measured process. He concluded that compliance with this process is not mismanagement and should not be held against DEP with respect to cost recovery. (Tr. Vol. 21, pp. 79-80.)

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[21] In reviewing witness Lucas' revised Exhibit 5, witness Wells concluded that if one were to remove the Mayo-specific events, Lucas' exhibit only indicates 4 permit exceedance violations for the other six DEP sites in the last 10 years.

Witness Wells further argued, persuasively in the Commission's view, that the groundwater extraction and treatment activity that DEP performed pursuant to the DEQ Settlement Agreement merely accelerated work that would have been required under CAMA in any event. (Id. at 76.) Although CAMA borrows heavily from the 2L Rules, including by incorporating the substance of its corrective action requirements, one key difference between the two laws is that CAMA's groundwater assessment and corrective action provisions are triggered by exceedances – not violations – of the 2L groundwater standards. In other words, unlike the 2L Rules, CAMA requires utilities to perform groundwater assessment and corrective action for all identified exceedances of the 2L groundwater[22] standards regardless of whether the exceedance amounts to a violation of the applicable groundwater standard.

The Commission determines that there is insufficient evidence that the Company would have had to have engaged in any groundwater extraction and treatment activities absent the obligations imposed upon it by CAMA and/or the CCR Rule.

The Commission determines that the limitations of witness Lucas's approach are demonstrated by his inability to answer with any specificity on cross-examination: "From 1920 until 2014, with respect to … [the] Company's ash basins in this state, what should we have done differently and when should … [it] have done it?" (Tr. Vol. 19, p. 35.) His response essentially was that "Somewhere along the line the Company should have taken some kind of action to not contaminate groundwater." (Id. at 36.) But the kinds of actions he appears to have favored – such as lining ash ponds when this was contrary to standard practice, or creating dry coal ash basins when for the most part the Company's industry peers were sluicing coal ash into wet basin impoundments, would (a) have cost money which would have been charged to customers, or (b) would have left the Company open to credible claims of "gold-plating," and therefore cost disallowance, which would have prevented the Company from moving forward with these suggested improvements in the first place. Witness Lucas and the Public Staff fault the Company for not taking steps that were not in accord with steps most of the industry was following, but at the same time disregarding responsibility of paying for that which they – in 20/20 hindsight – wish the Company had done.

No party disputes the reasonableness of the amount of groundwater assessment and treatment costs the Company seeks to recover in rates; rather the dispute relates to the fact the groundwater assessment and treatment costs were performed pursuant to a settlement agreement with DEQ. The testimony of witnesses Kerin and Wells demonstrates that these costs – amounting to $6,693,390 – were reasonably and

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[22] Id.; see also N.C. Gen. Stat. § 130A-309.211. When preparing a corrective action plan, CAMA does not require the utility to describe any 2L violation and instead required only a "description of all exceedances of the groundwater quality standards, including any exceedances that the owner asserts are the result of natural background conditions." N.C. Gen. Stat. § 130A-309.211(b)(1)a (emphasis added).

prudently incurred to comply with the Company's obligations under CAMA and the CCR Rule. The Commission determines that they therefore would be recoverable in rates, as would be the $88,000 in legal fees that witness Lucas also proposed excluding as settlement agreement expenditures were it permissible to view them as standard allowable expenditures but for DEP's admissions in the federal criminal court action where DEP pled guilty to mismanagement and the timing with compliance with CAMA.

The AGO, Sierra Club, and other intervenors make similar arguments that DEP has failed to keep pace with industry standards and therefore DEP should not be allowed to recover current environmental compliance costs in rates. The Intervenors argue that DEP should have done more than just comply with the current environmental regulations at the time. However, AGO witness Wittliff testified that the definition of industry standards is compliance with law.[23] (Tr. Vol. 15, p. 100.) Based upon the evidence presented in this case, with the exception of the federal criminal case to which DEP pled guilty, DEP has not been found liable for violations of the law. As stated above, the Commission will not use settlement agreements to find liability. The AGO asserts that this Commission should consider all of the seeps located at its ash basin sites and deny of recovery of CCR costs. However, as stated in the criminal case which covered engineered seeps, DEQ and DEP have been in long-standing negotiations as to whether seeps are a violation of law and since 2014 whether seeps should be covered by the NPDES permit. (Wittliff Ex. 5, pp.78, 95.)(Wittliff Ex. 5.2, p. 44.) According to statements made in the criminal case, DEQ has currently not made a determination on this issue.(Wittliff Ex. 5.2, p. 44.) The Commission finds witness Wells' testimony persuasive that any past violations by DEP do not give support to the amounts of cost disallowances advocated by the Intervenors and the Public Staff in this case.

Lastly, although the record is not crystal clear as to whether DEP is seeking bottled water costs, or the amount of any bottled water costs, and no party has asked for a specific disallowance for the cost of bottled water, the Commission finds that DEP shall remove from its request any costs for bottled water, if any, that it may have agreed to provide pursuant to any lawsuit.

Garrett and Moore: Off-Site Transportation and Disposal of Coal Ash and Related Costs

The Public Staff, through witnesses Garrett and Moore, asserts that the Company acted imprudently in arranging for off-site handling of CCRs from the Sutton and Asheville Plants, and contends that disposal should have occurred at to-be-constructed on-site landfills, thereby saving primarily on the cost of off-site transportation. Garrett

[23] Upon redirect, when asked how DEP's management of ash ponds were different from industry standards, AGO witness Wittliff responded, "Well, I think there were a number of companies that were doing exactly what Duke did." (Tr. Vol. 15, pp.112-13.) When asked as to whether there were any other ways besides compliance that DEP did not comply with industry standards, he responded, "I don't know … do you have a specific thing in mind that you're wanting?" (Tr. Vol. 15, 114.) He went on to testify that the "standard, is compliance." (Tr. Vol. 15, 114.)

and Moore also expressed concern with respect to the costs the Company agreed to pay with respect to Asheville Plant coal ash, contending that it was excessive. The Public Staff recommends that a $80.5 million disallowance be applied with regard to Sutton Plant coal ash (Tr. Vol. 18, p. 180), and that a $29.3 million disallowance be applied with regard to Asheville Plant coal ash (id. at 182), for a total recommended disallowance of $109.8 million. The Commission rejects these discrete adjustments but takes these allegations into account in its mismanagement adjustments. Company witness Kerin indicates that he does not disagree that an on-site landfill was the best solution for the Sutton Plant – indeed, at Sutton, the Company built an on-site landfill, which became operational in July 2017, and is placing coal ash in that landfill today. (Tr. Vol. 20, p. 65.) The issue with respect to an on-site landfill at both sites is feasibility in light of the basin closure deadlines imposed by CAMA, and in the case of the Asheville Plant, modified by the Mountain Energy Act of 2015 ("MEA"), which requires the Company to construct a new combined cycle power plant and facilitate the shut-down of the existing Asheville coal-fired plant by January 31, 2020. (Id. at 43.)

The CAMA and, in the case of the Asheville Plant, MEA, deadlines would provide the overarching framework by which prudency must be assessed, were the Commission to ignore the contributing factors leading to CAMA and were the Commission to ignore DEP's admitted mismanagement with respect to CCR activities in its criminal court pleas, because an alternative proposed action would have to be feasible in order to truly be an alternative. 1988 DEP Rate Order, at 15. Witness Kerin's rebuttal testimony shows that Garrett and Moore's proposed alternative – on-site disposal – was not feasible in the time frames available to the Company, particularly, as Kerin testified, "missing the required CAMA date was not an option …." (Id. at 39.)

The Commission finds merit in DEP's assertions that the Garrett and Moore timeline for Sutton "was a 'perfect world' scenario without due consideration of the inherent uncertainty of permitting any type of landfill, especially a CCR landfill, particularly during the regulatory and political environment of 2014." (Id. at 37.) Perfection is not the standard. As an example of imperfection, Kerin points to the unexpected "environmental justice" review imposed by DEQ (Id. at 65-67), that caused a six-month delay in the issuance of the Sutton on-site landfill permit. Also, within weeks of the permit's final issuance, Hurricane Matthew blew through the area, impacting landfill construction. The Commission, however, agrees with Garrett and Moore and disagrees with witness Kerin that the moratorium prevented DEP from constructing a new CCR repository in the footprint of a preexisting repository once it had been excavated. DEP's reading of the provisions of the statute is strained and out of accord with a common sense interpretation. (Id. at 67-68.) However, DEP may have acted in response to its erroneous and overly cautious interpretation in light of the compressed time frame under which it operated.

DEP also confronted two limitations dealing with NCDEQ standards addressing dewatering and closure by removal of CCRs from surface impoundments. The standards address remediation of discharges or releases of contaminants into soil and groundwater to cleanup levels to meet the State's 2L groundwater standards.

To fully excavate CCRs for repurposing, bulk dewatering is necessary as well as interstitial dewatering from submerged ash. DEQ completed applicable regulatory requirements in 2015. For Sutton, the requirements were specifically detailed in the amended and approved NPDES permit in December 2015. As these dewatering requirements were not defined by DEQ in 2014 or 2015, a viable option for converting the existing CCR impoundment at Sutton to a new landfill did not exist then.

DEQ's cleanliness requirements set forth in its "Coal Combustion Residuals Surface Impoundment Closure Guidelines for Protection of Groundwater" were not completed until November 2016. DEP could not convert the Sutton impoundment to a new CCR landfill in 2014 or 2015 until the guidelines had been established. Therefore, compliance with CAMA deadlines through reliance solely on an on-site landfill was not possible. (Tr. Vol. 20, pp. 35-37.)

In addition, while "perfect world" scenarios may appear appropriate in an after-the-fact analysis, once CAMA became law, prudent planning required the Company to meet "real world" difficulties as and when they arose, to ensure that the legislatively fixed August 1, 2019 deadline would be met. To do so, the Company devised for Sutton a two-part plan that included both the construction of an on-site landfill and off-site disposal of some portion of the coal ash – approximately two million tons, of the 6.6 million tons of coal ash in the Sutton coal ash basins. (Id. at 39.) Had the Company not arranged for off-site disposal, it would have been required to transport the 6.6 million tons of coal ash from the coal ash basins to the new on-site landfill in the 25-month period from the issuance of the landfill's operating permit (July 7, 2017) to CAMA's August 1, 2019 closure deadline. In the Commission's view, this was an unreasonable task. (Id. at 40.) The Company's Sutton plan, therefore, in light of the CAMA deadlines and the delays in obtaining permits, does not rise to the level of imprudency the standard the Commission deems required. Therefore, discrete cost disallowances are not approved.

The Commission determines that similar considerations come into play when assessing the prudence of the Company's decision to transport Asheville Plant CCRs offsite once CAMA became law. (Id. at 42.) The MEA, while extending the closure deadline to August 1, 2022, required construction of a new combined cycle plant. (Id. at 43.) The new plant must be built on the site of one of the Asheville Plant's basins. This meant that that basin had to be emptied of coal ash. That, along with the need for an extensive construction laydown area necessary to allow efficient construction of the new plant, left no space at the Asheville Plant site in which to build an on-site landfill. As witness Kerin put it, the MEA "effectively made construction of a new on-site CCR landfill technically infeasible given the short time period to replace the coal-fired generation by 2020, and close the coal ash basins by 2022." (Id. at 43.)

In the 1988 DEP Rate Order, this Commission stressed the importance of carefully examining the Company's explanations of the decisions it made, as of the time they were made, and emphasized that the credibility of the decision-makers, particularly in juxtaposition to after-the-fact analyses, presented by Intervenor-retained consultants.

See, e.g., 1988 DEP Rate Order, at 29. The Commission does not question the bona fides or expertise of Garrett and Moore; indeed, witness Kerin notes (and appreciates) that they "conducted a thorough and principled analysis" of the Company's CAMA/CCR Rule compliance costs, and that he agreed with "the majority of their conclusions." (Tr. Vol. 20, p. 56.) The Commission determines, however, that witness Kerin has "lived" this project since its inception (Id. at 32), and relies upon his testimony regarding the decisions made, and determines that the Garret and Moore adjustments, other than to the extent addressed indirectly in the Commission's management penalty, will not be adopted.

Witnesses Garrett and Moore also asserted that that DEP exclusively should have utilized the Cliffside landfill in lieu of the Homer, Georgia landfill due to closer proximity and the lower cost of the Cliffside landfill. (Tr. Vol. 18, pp. 182-83.) However, in live testimony at the hearing, witnesses Garrett and Moore accepted that moving the required coal ash from Asheville to Cliffside, as they testified should have been done, would have amounted to 30,162 truckloads, 3,619,440 miles of driving, equal to about 145 trips around the earth. (Id. at 198-99.) They also agreed that for a six-month period of time this would require moving 4,292 tons of coal ash per day, by 232 trucks per day, which means one truck leaving the site every two minutes. (Id. at 199.)

Witness Kerin, noting that Garrett and Moore had not accounted for over 500,000 tons of coal in their analysis, demonstrated the infeasibility of their approach. He indicated on cross-examination by counsel for the Public Staff that the Company was already sending 195,000 tons of coal ash to Cliffside at that time, and that the additional 558,000 tons proposed by witnesses Garrett and Moore would have resulted in about 40,000 loads, "or loading a truck every minute and a half, loading, moving, scales, washing, getting it through the site and getting it on the highway. Virtually impossible at that site, if you have ever been to the Asheville site where the '82 basin is, to move that many trucks through that site and out of that basin in a minute and half per truck." (Tr. Vol. 20, p. 113.) The Commission agrees with DEP that infeasible options do not support a finding of discrete adjustments for imprudence. 1988 DEP Rate Order, at 15. The Commission determines that witness Kerin's testimony demonstrates that the Company's actions and real-time decisions regarding the Ashville site were in fact reasonable and prudent in the context of the requirement of CAMA and the MEA, and that the costs, in the context of analysis the witnesses undertook, were in fact prudently incurred. As such, no discrete disallowance is approved with the exception of the increased contracted disposal costs with Waste Management, Inc. of $9.5 million. The Company essentially agreed that this adjustment for contractual coal ash moving expense was appropriate and the Commission agrees.

Conclusion with respect to January 1, 2015 – August 31, 2017 Costs

The Commission finds that the costs are known and measurable, when viewed in isolation and without regard to the broader context of DEP's admission of criminal negligence in the management of its CCR activities, and the cost increases arising from the CAMA schedule, the costs, with noted exceptions, were reasonably and prudently incurred, and are used and useful in the provision of service to customers. But for the Company's admissions of mismanagement and the extent such conceded mismanagement was a contributing factor resulting in the enactment of CAMA, they should be recoverable from customers.

But for the management penalty discussed below, the Commission deems the Company's proposal, which submits that the amortization period should be five years, would be reasonable and appropriate. The five-year period suggested by the Company is identical to the period over which Dominion's already-incurred coal ash basin closure costs were amortized in the 2016 DNCP Rate Case. It further had the virtue, when originally proposed, of being identical to the five-year period over which the Company proposed to return to customers excess deferred taxes resulting from the change in North Carolina's income tax rate (*see* Tr. Vol. 6, p. 129), although that time period was later reduced as part of the Partial Settlement with the Public Staff to four years. While the amount of the excess deferred tax regulatory liability (approximately $150 million; *see* Peedin Revised Exhibit 2, Schedule 1, Line 1) is less than the coal ash basin closure cost deferred balance that the Company seeks recovery of in this case (approximately $242 million), both are substantial. It would be reasonable to use similar amortization periods for both the deferred tax regulatory liability returned to customers (with a return) and the coal ash basin closure regulatory asset collected from customers (also with a return).

In summary, the Commission determines that but for admitted mismanagement and its being a contributing factor to CAMA, its coal ash basin closure costs actually incurred over the period from January 1, 2015 through August 31, 2017 are (a) known and measurable, (b) reasonable and prudent, and (c) used and useful, and, as such, that it is entitled to recover those costs in rates. DEP has further shown that its proposal that these costs be amortized over five years, with a return on the unamortized balance, would have been reasonable.

<u>The Public Staff's 50/50 "Equitable Sharing" Concept</u>

Witnesses Lucas and Maness, for the Public Staff, propose a 50% disallowance of the Company's already-incurred coal ash basin closure costs through what Maness terms a 50/50 "equitable sharing" arrangement between shareholders and customers. (Tr. Vol. 18, p. 309.) He implements this sharing concept with two steps. First, he removes the unamortized coal ash basin closure costs from rate base, thereby eliminating any return on that unamortized balance. (<u>Id.</u>) The second step is to choose an amortization period that will result in the desired level of "sharing." (<u>Id.</u> at 10.) As the Public Staff's desired level is 50/50, mathematically that results in a 26-year amortization period at the rate of return the Company and the Public Staff agreed, subject to the Commission's approval, was appropriate in this case. (<u>Id</u>. at 344-45.) As witness Maness acknowledged, with a different rate of return, "the number of years might be different to reach the 50 percent mark." (Tr. Vol. 19, p. 59.)

The Commission agrees with DEP that this adjustment is not based on an applicable standard. The Public Staff chose this number, then adjusted the mechanism to achieve that level of disallowance. The Public Staff provides insufficient justification for the 50/50 as opposed to a 60/40, or 80/20. Witness Mannes indicates merely that it "was the judgment of the Public Staff … that 50 percent was a reasonable percentage." (Id.)

A "determining principle" or prudency standard is missing from the Public Staff's 50/50 "equitable sharing" proposal. See Tate Terrace Realty Investors, Inc. v. Currituck Cty., 127 N.C. App. 212, 222-23, 488 S.E.2d 845, 851-52 (1997). As such, were the Commission to adopt it, the Commission very well could be found to be acting arbitrarily and capriciously, and subject itself to reversal. An illustrative case is Sanchez v. Town of Beaufort, 211 N.C. App. 574, 710 S.E.2d 350 disc. review denied, 365 N.C. 349, 715 S.E.2d 152 (2011)

Ultimately, the Public Staff, through Witness Maness, indicates that it is "up to the Commission's discretion to determine what [the] sharing should be." (Tr. Vol. 19, p. 69.) Even if the equitable sharing mechanism were without legal impediments, the Commission chooses in the exercise of its discretion not to adopt this recommendation but instead on an alternative remedy addressed below. The Public Staff bases its proposal on two principles: first, the Company's alleged past failures, as detailed in the testimony of Public Staff witness Lucas, to prevent environmental contamination from its coal ash basins, and, second, an asserted "history of approval of sharing of extremely large costs that do not result in any new generation of electricity for customers." (Tr. Vol. 18, p. 309.)

As to the first asserted predicate, the parties dispute the existence of failures. The Commission addresses Wells' testimony, above, but whether or not the Company were guilty of some sort of violation appears not to be material to the Public Staff's 50/50 sharing proposal. Witness Maness admitted, in response to questions from the Chairman, that all of these alleged acts or failures to act occurred in the past. (Tr. Vol. 19, pp. 60-61.) Witness Maness's response to the Chairman's questions leads to the true heart of the matter – the Public Staff's position, simply stated, is that it does not matter if the Company's actions in incurring the CCR Rule and CAMA compliance costs were prudent – the Public Staff's 50/50 equitable sharing proposal would still apply. As Maness testified, "[E]ven if you left out specific acts or omissions of the Company and assumed everything was prudent, aboveboard" (Tr. Vol. 19, p. 61), the Public Staff would (at least "likely") still recommend the 50/50 equitable sharing proposal. (Id.) Accordingly, the real rationale for the Public Staff's proposal appears to be witness Maness's second predicate: the proposition that the Commission has a "history of approval of sharing of extremely large costs that do not result in any new generation of electricity for customers." (Tr. Vol. 18, p. 309.)

According to witness Wright, there is "no provision of Chapter 62 requiring different treatment for 'extremely large costs'" (Tr. Vol. 20, p. 141), and, in any event, witness Wright detailed any number of "extremely large cost" items not associated with new generation for which cost recovery is routinely allowed. (Id.) This is yet another example of the arbitrariness inherent in the Public Staff's sharing proposal. While the Commission in the past has made decisions to avoid "rate shock," that equitable principle does not apply here in the context of the recommended cost disallowances.

On another level, it appears that witness Maness is saying that this rationale for the sharing proposal is grounded in the Public Staff's view of the discretion available to the Commission. He states first that pursuant to G.S. 62-133(b)(1), and with the exception of construction work in progress under certain circumstances, "the only costs that the Commission is required to include in rate base are … the 'reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period ….'" (Tr. Vol. 18, p. 310.) He indicates that he is advised by counsel that "beyond these requirements what is and what is not in rate base is fully within the Commission's discretion to decide, as long as the rates set thereby are fair and reasonable to both the utility and the consumers." (Id.) The Commission determines that the Public Staff's view of the Commission's discretion is overly broad, however, and not supported with the cited Supreme Court precedent. Likewise, to the extent the Public Staff is correct in its arguments that the Commission has the discretion to accept the Public Staff's equitable sharing remedy, the Commission declines to do so in favor of an alternative remedy addressed below.

As expressed through witness Maness's testimony, the Public Staff looks to the Commission's Order Granting Partial Increase in Rates and Charges in Docket No. E-2, Sub 526 (Aug. 27, 1987) (the 1987 DEP Rate Order) and its affirmance by the Supreme Court in Thornburg I, 325 N.C. 463, 385 S.E.2d 451 (1989) as precedent for its 50/50 equitable sharing concept. The Commission determines that the more compelling precedents are the 1988 DEP Rate Order and the Commission's Order Denying Motions for Reconsideration in the 1988 DEP Rate Case (Docket No. E-2, Sub 537) (1988 DEP Reconsideration Order), and the Supreme Court's reversal in part of those Orders in Thornburg II, 325 N.C. 484, 385 S.E.2d 463 (1989). The principal issue in the 1987 DEP Rate Case/Thornburg I was whether the Company could recover in rates any portion of the costs associated with the abandoned Units 2, 3, and 4 of the Shearon Harris nuclear plant. The Commission had previously decided that the Company could amortize the unrecovered costs associated with these abandoned units over a ten-year period, but that "no ratemaking treatment should be allowed which would have the effect of allowing … [the Company] to earn a return on the unamortized balance." 1987 DEP Rate Order, at 61. Over the objections of the AGO, the Commission decided to continue to follow that process in the 1987 case – it allowed amortization of abandonment costs over a ten-year period as an operating expense under G.S. 62-133(b)(3) and 62-133(c), but no return authorized on the unamortized balance. The North Carolina Supreme Court, in a passage extensively quoted in witness Maness's testimony (see Tr. Vol. 18, pp. 311-12), affirmed the Commission's decision, holding that G.S. 62-133(b)(3) and 62-133(c) were elastic enough to include abandonment costs as utility "expense," and that G.S.. 62-133(d), which allows the Commission to factor in "all other material facts of record that will enable it to determine what are just and reasonable rates," also provided support for the Commission's decision. The Court further held that as a matter of policy a return of, but not a return on, the abandonment costs was appropriate. Thornburg I, 325 N.C. at 476-81, 385 S.E.2d at 458-61.

In Thornburg I, the Court held specifically that the Commission's recovery but no return decision was "within the Commission's discretion" and would not be disturbed. Id. at 481. That decision effected a "sharing" between the Company's shareholders, on the one hand, and its customers, on the other – shareholders received a return of the costs, but no return on the costs. It is based upon this holding that the Public Staff, through witness Maness's testimony, contends that "reasonable rates can include a sharing between ratepayers and investors with regard to plant cancellation costs" (Tr. Vol. 18, p. 311), and that the Commission possesses discretion to implement this sharing.

There are, however, significant distinctions between the 1987 DEP Rate Case/Thornburg I and the present case. First and foremost, this case does not involve "abandoned plant" or cancellation costs. Rather, it involves "reasonable and prudent" and "used and useful" expenditures by the Company, similar to the Commission's determination in the 2016 DNCP Rate Order. As such, the authority the Public Staff relies upon to support its "equitable sharing" concept does not support the exercise of discretion as the Public Staff maintains. This can be seen when examining other prior orders of this Commission and the correct Thornburg case: the 1988 DEP Rate Order, the 1988 DEP Reconsideration Order, and Thornburg II.

In the 1988 DEP Rate Case, the principal issue for decision was the reasonableness and prudence of the costs of constructing and placing into service Unit 1 of the Shearon Harris nuclear plant. The Commission found that for the most part, Harris Unit 1 costs were reasonable and prudent, and that part of the 1988 DEP Rate Order was upheld by the Supreme Court. 325 N.C. at 489, 385 S.E.2d at 465-66 (finding "no error" in that part of the Commission's Order). However, a part – $570 million- worth – of the costs the Commission considered were incurred in connection with facilities to be shared with Units 2, 3, and 4, units that the Company had abandoned. The Commission found that while these costs were prudently incurred, they should be shared between the Company's customers and its shareholders. The Commission found that approximately $180 million of those costs were properly classified as "abandonment" costs and should be borne by shareholders. 1988 DEP Rate Order, at 112-14. The remaining $390 million were left in rate base.

Responding to the Public Staff's request that the Commission reconsider this decision and remove the entire $570 million from rate base on the grounds that all of it related to abandoned plant, the Commission reaffirmed its decision in the 1988 DEP Reconsideration Order and provided additional explanation for its ruling. It stated (1988 DEP Reconsideration Order, at 2-3) that the Public Staff's request that the full $570 million for the common facilities be treated as abandonment costs was based upon a "misunderstanding" of the 1988 DEP Rate Order and the Commission's objective in splitting this $570 million item into $390 million of rate base and $180 million of cancellation costs. The Commission did not (it says in the 1988 DEP Reconsideration

Order) intend to treat the "excess common facilities" as abandoned plant; rather, it effected an "equitable sharing" (emphasis added) of the $570 million between customers and shareholders. The Commission reiterated that the Company's choice of the cluster design – which engendered the shared facilities – was reasonable and prudent, and that, except as specifically indicated in the 1988 DEP Rate Order, the costs of the Shearon Harris plant were "reasonable and prudently incurred." Thus, the Commission found, the $570 million at issue was also reasonably and prudently incurred.

Nevertheless, the Commission held (Id. at 4-5) that it was appropriate to share the $570 million at issue, and it indicated that it arrived at the allocation (essentially one-third to cancellation costs and two-thirds to rate base) on its own and adopted it "for reasons of fairness and equity." It held that it continued "to believe that a reasonable and equitable apportionment of the burden and risks associated with … [the Company's] prudent investment in common facilities is appropriate." It stated further that its assignment of $180 million as the value of the Company's prudent investment in common facilities to be treated as cancellation costs for ratemaking purposes was an appropriate exercise of its "regulatory discretion."

The North Carolina Supreme Court disagreed. The Court held that the Commission did not possess the discretionary power to effectuate its "equitable sharing" decision. Rather, the facilities were either "used and useful," and therefore in rate base, or they were not. The Court looked to the Commission's finding that the facilities in question were "excess common facilities," and held that "excess" facilities were not "used and useful" as a matter of law. 325 N.C. at 495, 385 S.E.2d at 469. Accordingly, looking to the correct Commission and Supreme Court precedent, these determinations are insufficient support for the Public Staff's "equitable sharing" concept.

In addition to the costs of abandoned nuclear construction, witness Maness contended that there is precedent for approval for sharing of extremely large costs that do not result in any new generation of electricity for customers. He asserted that sharing between ratepayers and shareholders has also been approved for environmental cleanup of manufactured gas plant (MGP) facilities. (Id. at 309-10, 343-44.) In rebuttal, witness Wright testified that the Commission's treatment of environmental cleanup of manufactured gas plants does not support the Public Staff's proposed cost sharing, and referred to his direct testimony that MNG [MGP] plant costs differ from coal ash disposal costs, both in terms of the time that elapsed between the actual usage of the facility and the environmental-related cost recovery, and in terms of ownership. In addition, he noted that MNG [MGP] facilities, like abandoned nuclear plants, were found not to be used and useful. He noted further that there is no need to rely on a 23-year-old cost recovery example from a different industry, dealing with assets last used more than 70 years ago, when the best example of the Commission's treatment of coal ash disposal costs can be found in the Dominion case that was decided one year ago. (Tr. Vol. 20, pp. 138-40, 173.) The Commission also notes that the North Carolina Commission was in the minority among states on the way that it handled MGP costs, ie, the "sharing of costs." The majority of states granted full recovery of MGP costs. See Recovery by Utilities of

Expenditures on Manufactured Gas Plant Claims: Recent Developments Regarding Insurance Coverage and Rate Relief, Nicholas Fels, William Skinner and Saul Goodman, p. 44 (August 1, 1996). The Commission finds that the Commission's decision in Docket No. G-5, Sub 327, Public Service Co. of North Carolina, 156 PUR 4th 384 (October 7, 1994), is distinguishable from the CCR remediation costs at issue in this case and moreover not precedent the Commission chooses to follow to provide for sharing in the present case.

The issue that remains is whether the already-incurred costs expended by the Company in connection with its CCR Rule/CAMA compliance obligations are "used and useful" and "prudent and reasonable." DEP argues that the Commission has already decided this issue, in the 2016 DNCP Rate Order, where it held that costs expended for the identical purpose were "used and useful." 2016 DNCP Rate Order, at 60-62, and that were the Commission to decide differently in this case, the Commission would be acting arbitrarily and capriciously. DEP cites Gregory v. County of Harnett, 128 N.C. App. 161, 164-65, 493 S.E.2d 786, at 788 (1997) (County Commission, which approved a zoning application restricting mobile home development three days after rejecting an almost identical application, acted arbitrarily and capriciously). [24] The Commission disagrees. While the Commission's Order here is consistent with the logic of its DNCP Order, it disagrees with DEP that it is bound to follow it. The Commission expressly stated that its CCR determinations in the DNCP Order were non-precedential. Moreover, this is a ratemaking decision in which the Commission exercises its legislative authority.[25] Its past decisions are neither binding, res judicata[26] nor stare decisis.[27]

In its cross-examination questions (*see*, *e.g.*, Tr. Vol. 14, pp. 236-37), the Public Staff suggests that if the Company truly thought the coal ash basin closure costs were "used and useful" it should have put them directly into rate base as opposed to deferred into a regulatory asset via ARO accounting. Witness Maness stated such in his responses to the Chairman's questions, indicating that he had struggled with the issue but had not "found anything direct yet" in the accounting literature. (Tr. Vol. 19, p. 66.) The accounting issue, as far as witness Maness is concerned, is how the Company's coal ash basin closure costs could be classified as "plant," and therefore eligible to be

[24] While certain Intervenors argue that Dominion's situation is different from the Company's in that Dominion had not committed environmental "violations," this purported distinction is of no moment. Dominion in fact has been the subject of regulatory scrutiny with respect to its Chesapeake Plant, and has been the target of lawsuits brought by environmental advocacy organizations in connection therewith. (Tr. Vol. 20, pp. 135-37, 171-72, 189.)

25State ex rel. Utils. Comm'n v. Edmisten, 294 N.C. 598, 242 S.E. 2d (1978) (ratemaking activities of the Utilities Commission are a legislative function).

26 Id. (only specific questions actually heard and finally determined by the Utilities Commission in its judicial character are res judicata).

27 State ex. Rel., Utils. Comm'n v. Carolina Utility Customers Ass'n, Inc., 348 N.C. 452, 500 S.E. 2d 693 (1998) (Utilities Commission orders in rate cases are not within the doctrine of stare decisis).

included in rate base, when they are actually accounted for in an ARO, which deals with retirement costs. (Id.) witness Maness also indicates that the Company "chose[] not to propose to include these type of costs … as utility plant and service." (Id. at 67.)

The Commission disagrees with the Public Staff's characterization. First, the Company did put coal ash basin closure costs directly into rate base. See Bateman Supplemental Ex. 1, p. 54. The costs were included in the Working Capital section of rate base (Id. at 53), and no party has taken the position that their inclusion therein was inappropriate.[28]

The AGO makes a related argument in its post-hearing Brief. The AGO argues that DEP failed to request in advance permission to create a deferred account. Contrary to witness Maness's indication that the Company had any "choice" in the matter, and the AGO's argument, upon the passage of CAMA and the promulgation of the CCR Rule, the Company was required by GAAP to establish an ARO. The accounting guidance (ASC 410-20-15-2) states that it applies to "Legal obligations associated with the retirement of a tangible long-lived asset," and "legal obligation" is defined (ASC 410-20-20) as an "obligation that a party is required to settle as a result of an existing or enacted law …." (Emphasis added). Once it became clear that the new laws and regulations governing coal ash would require closure of the Company's existing coal ash basins, GAAP required that an ARO be established, and the Company had no choice in the matter. As the Public Staff and the Commission have noted previously, "Statements of the FASB are officially recognized by the Securities and Exchange Commission (SEC) as authoritative with regard to GAAP in the United States, and the requirements included in those Statements are essentially mandatory for any publicly traded entity." See Order Granting in Part and Denying in Part Request for Deferral Accounting, Docket E-2, Sub 826 (April 4, 2003), at 13. Moreover, DEP notified the Commission of its establishment of the ARO.

As a matter of law, it is not necessary that something be classified as "plant" in order to be properly included in rate base. Rather, the issue is the source of the funds. In State ex rel. Utils. Comm'n v. Virginia Elec. & Power Co., 285 N.C. 398, 206 S.E.2d 283 (1974) (VEPCO), for example, the Supreme Court held that working capital (which is not "plant") could be included in rate base, so long as it was provided by the utility:

> Like any other business, a public utility must at all times have on hand a reasonable amount of materials and supplies and a reasonable amount of funds for the payment of its expenses of operation. While Chapter 62 of the General Statutes makes no reference to working capital, as such, the utility's own funds reasonably invested in such materials and supplies and its cash funds reasonably so held for payment of operating expenses,

[28] While witness Maness removed the Company's coal ash basin closure costs from Working Capital section of rate base, he did so not because of any quarrel with their inclusion therein, but in order to give effect to the Public Staff's 50/50 "equitable sharing" proposal. (*See* Tr. Vol. 18, p. 309.)

> as they become payable, fall within the meaning of the term "property used and useful in providing the service" … and are a proper addition to the rate base on which the utility must be permitted to earn a fair rate of return.
>
> Conversely, the utility is not entitled to include in its rate base funds which it has not provided but which it has been permitted to collect from its customers for the purpose of paying expenses at some future time and which it actually uses as working capital in the meantime.

285 N.C. at 414-15, 206 S.E.2d at 295-96. As the Company appropriately accounted for coal ash basin closure costs in the working capital section of rate base, and as these funds were investor-furnished, not customer- furnished, VEPCO holds that they are "used and useful" within the meaning of G.S. 62-133(b)(1) in the provision of service. As such, the Company is entitled to earn a return on those funds over the period in which the costs are amortized.[29]

A concrete illustration highlights this issue more clearly. Take, for example, the new coal ash landfill that the Company constructed at the Sutton plant. The landfill "went into service in July … [2017], and … [the Company is] placing ash in the landfill today." (Tr. Vol. 20, p. 65.) The Public Staff, through its consultants Garrett and Moore, has no quarrel with the construction of the landfill or its cost, except for the liner chosen, and agrees that the funds expended in constructing this landfill were reasonable and prudent. The Public Staff maintains however that the landfill should have been constructed sooner and so has proposed a disallowance of the cost of off-site transportation and disposal of coal ash from the Sutton plant. The landfill is "used and

[29] Even if for some reason some portion of the Company's already-incurred coal ash basin closure costs might not be classified as "used and useful," that does not mean that they are not recoverable or that the Company may not earn a return on them. In Dominion's 2012 Rate Case, the utility sought to recover over a three-year amortization period the unrecovered costs associated with one of early-retired coal-fired plants (North Branch), with DNCP earning a return on the unamortized balance. The Public Staff agreed that the costs of the retired plant, although not placed into rate base, should be recovered over an amortization period, and that DNCP should earn a return on the unamortized balance, but advocated for a ten-year rather than three-year, amortization period. The Public Staff argued that, as was the case in Thornburg I, the Commission had authority to treat these unrecovered costs in this fashion within the discretionary authority granted the Commission through G.S. 62-133(c) and 62-133(d). See Order Granting General Rate Increase, Docket No. E-22, Sub 479 (Dec. 21, 2012), at 36. The Commission agreed, and implemented the Public Staff's suggestion. *Id*. at 37. Accordingly, the Commission, in the event that it is later determined that some portion of the Company's already-incurred coal ash basin closure expense is not "used and useful" within the meaning of G.S. 62-133(b)(1), may nevertheless allow that portion of those costs to be amortized in the same manner as the portion of "used and useful" costs, with the Company earning a return on the unamortized balance. For the reasons stated herein, were the "used and useful" decision the Commission has reached be found to be in error, the Commission would nevertheless approve the Company's cost recovery proposal in all respects, and would exercise its discretion to achieve that result.

useful." It consists of liners, for example, that are capital items with service lives in excess of one year. It stores coal ash which itself is a byproduct of electricity generation, and is required to be stored in a landfill by the CCR Rule and/or CAMA. Yet the Public Staff is also saying that because the costs of construction are accounted for in an ARO – as required by GAAP, to which the Company is subject – they are somehow not "used and useful." The Commission rejects this label-driven classification.

Witness Maness testified that whether the CCR remediation costs were used and useful was not a determinative factor in justifying its equitable sharing remedy. (Tr. Vol. 19, pp. 64-67) He testified that where capital costs such as constructing lined repositories or caps over existing repositories are accounted for as an ARO, accounting conventions for ARO's control. As such, in addition to its determinations above, the Commission determines that the debate between the parties on this issue is not one the Commission is required to resolve. Costs placed in an ARO account are eligible for deferral and amortization and for earning on the unamortized balance. As such, even if the remediation costs are ARO expenditures, they are eligible for ratemaking treatment as though they are used and useful assets.

Conclusion as to Non-Cost Specific Disallowance Proposals

The disallowance methodologies proposed by the AG, CUCA, and the Public Staff discussed above fail because they fail to comply with the Commission's prudence framework, established in the 1988 DEP Rate Order and upheld by the Supreme Court in Thornburg II. They avoid the detailed analysis that an appropriate framework requires. Public Staff witness Lucas, for example, noted that the Public Staff advocates "equitable sharing" because of the difficulties and complicating factors attendant upon detailed cost analysis (Tr. Vol. 18, pp. 59-61), and he reiterated his contention on cross-examination, noting that "There is nothing wrong with a simple solution." (Tr. Vol. 19, p. 22.) However, the Commission's prudence framework requires a detailed and cost-specific analysis to the extent the Commission resolves the CCR disputes on the basis of discrete prudence assessments alone. The Company's costs are presumed reasonable and prudent unless challenged, and the challenges presented must (1) identify specific and discrete instances of imprudence; (2) demonstrate the existence of prudent alternatives; and (3) quantify the effects by calculating imprudently incurred costs. 1988 DEP Rate Order, at 15. The methodologies proposed do not do that, and the Commission determines not to accept them.

In addition, were the Commission to disallow reasonably incurred and prudent costs in the magnitude suggested by the Public Staff (50% disallowance) through adjustments advocated, much less the higher or unspecified disallowances suggested by CUCA and the AGO, the result when translated into rates would be unjust and unreasonable, while the Commission's charge is to fix rates that are, to the contrary, just and reasonable. G.S. 62-131(a).

Company witness De May, asked his view on the likely reaction of the investment community to a Commission decision accepting the Public Staff's 50/50 "equitable sharing" proposal, expressed concern. He indicated, first, that "coal ash, to the financial community, doesn't look a whole lot different … to the other environmental regulations that have come to this industry over the many decades." (Tr. Vol. 8, p. 434.) He continued:

> Just looking at the rating agency reports and the analysts' reports, you could see that everyone is just sitting, waiting to see what the impact … [of] coal ash recovery will be to our company. And I think there is an expectation, as one analyst from Guggenheim [put it] … that recovering environmentally-related investments coupled with … our track record on getting environmental cost recovery, as well as precedent in doing so by this Commission [that] gives the [financial] community some confidence that we are going to get through this just like we have gotten through the Clean Air Act and through all of the clean smokestack legislation. All of these things have come to our industry, and come to our company, and we have dealt with them. This is no different.

(Id. at 434-35.) De May concluded, however: "[I]f the Public Staff position on coal ash were to be imposed upon our company, I think you would be looking at a totally new day in the way investors look at our company …." (Id. at 435.)

As Company witness Hevert notes, "[W]e cannot underestimate the importance to investors of a consistent and constructive regulatory environment. … In fact, 50.00 percent of the factors that Moody's Investor Service considers in determining credit ratings are related to the nature of regulation. From that perspective, it is clear Staff's recommendation implies a level of risk that would negatively affect both debt and equity investors and would increase the cost of capital to customers." (Tr. Vol. 8, p. 167.) The Commission acknowledges the danger and repercussions of changed investor perceptions of the regulatory environment. As it stated in the Company's 2013 rate case:

> Moreover, the Commission in establishing a rate of return on equity and other cost of service determinations is mindful that should it set the rate of return on equity too low, the impact on long term rates may be harmful to ratepayers. 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 DEP Rate Order at 37 (emphasis added).

While the Commission's observation regarding the regulatory environment was specifically made in the context of its discussion of return on equity, the observation is apt in the cost recovery context as well. The North Carolina Supreme Court, rejecting in

Thornburg I the AGO's argument that no abandoned plant/cancellation costs be charged to customers, observed that the AGO's position:

> [T]hough initially placing the entire cost upon the shareholders, may actually in the long term be less favorable to the ratepayers …. As one commentator has noted:
>
> > [I]n the long run, consumers end up paying—and paying twice—because what they gain by "saving" cancellation costs, they lose in higher rates of return as well as in diminished utility stature in the capital markets.
>
> Olsen, Statutes Prohibiting Cost Recovery for Cancelled Nuclear Power Plants: Constitutional? Pro-Consumer?, 28 Wash.U.J.Urb. & Contemp.L. 345, 377 (1985).

325 N.C. at 480-81, 385 S.E.2d at 460-61.

The Commission has considered this evidence and these arguments when framing its resolution in this matter. The Commission has further considered the AGO's arguments regarding DEP's criminal convictions when assessing its management penalty.

Sierra Club witness Quarles testified that continued storage of coal ash at Roxboro and Mayo poses significant environmental risks, and concluded that closure in place at these basins would allow continued contamination of downgradient groundwater and violate the technical standards of the CCR Rule. Witness Quarles further testified that removal of coal ash from DEP's CCR basins would reduce the concentrations and extent of this contamination. (Tr. Vol. 13, pp. 132-73; 175-77.) However, he admitted on cross- examination by Public Staff counsel that excavation and moving the ash at Mayo and Roxboro to lined landfills would increase the cost for closure. (Id. at 180.) Further, witness Quarles made no effort to quantify the economic impact of his recommendations. The Commission is not persuaded by the evidence presented by witness Quarles that the Commission is in a position at this time to determine whether DEP's closure plans at Roxboro and Mayo are reasonable and prudent. As a result, the Commission declines at this time to direct DEP to pursue any particular closure plans at Roxboro and Mayo.

The Sierra Club further asserts that all of the coal ash closure costs are the result of unlawful discharges and are not recoverable pursuant to G.S. 62-133.13. The Commission rejects the Sierra Club's reading of G.S. 133.13. The costs being incurred are not resulting from an unlawful discharge as defined by the statute, which is a discharge that results in a violation of State or federal surface water quality standards. Rather, DEP is incurring the costs to comply with the federal CCR rule and CAMA.

NC WARN has argued that DEP should not make a profit from selling coal ash from its existing basins. There is no evidence in the record that DEP is profiting from the sale of coal ash. Rather, any sale of coal ash merely reduced the remediation costs that

DEP otherwise incurred and any payments made for its beneficial reuse offset those remediation costs.

The Commission's Cost of Service Penalty

The costs DEP has incurred through the end of the test year as adjusted in coal ash remediation tasks have been substantial, and the Company will continue on an annual basis to incur a substantial level of costs through approximately 2028. The vast majority of these costs would have been incurred irrespective of management inefficiency in order to comply with EPA CCR requirements. When DEP initially constructed coal ash impoundments and transported CCRs to them many decades ago, it did so in accord with the prevailing industry practices at the time, especially in this part of the country. In part and over time this was in response to environmental regulations requiring the removal of pollutants such as CCRs from the coal plant smokestacks to reduce air pollution.

Over time, the EPA and other environmental regulators have scrutinized the impact of CCRs in unlined repositories on surface and ground water and have assessed the extent to which harmful constituents in CCRs exceed those naturally occurring in the environment and their impact on human health. One long-lasting debate before EPA addressed the extent to which CCRs should be classified as hazardous waste under RCRA, a debate only recently resolved. Had EPA classified CCRs as a hazardous waste, economic reuse in all likelihood would have become an impossibility.

Another area of scrutiny has been the appropriate need for and method of remediation with respect to closing and potentially moving CCRs from unlined impoundments.

Many of the criticisms of DEP's CCR remediation practices raised in this case, before the federal district court in the criminal proceeding and before other courts and administrative agencies, address issues such as seeps from impoundment dikes, failure to adequately maintain risers, improper maintenance of dikes, lax reporting, exceedances and NPDES violations with respect to surface water discharges. The primary and ultimate remediation however is dewatering and excavation of and transportation from existing unlined impoundments and construction of new lined impoundments or, for older discontinued impoundments that qualify, caps preventing rainwater intrusion. This is where the vast majority of the billions of dollars of CCR remediation costs must be spent. This ultimate remediation step is necessary to prevent leachate from infiltrating groundwater from the bottom of unlined basins, but would have been required irrespective of the harms that constitute other alleged mismanagement. In addition, this remediation process cures other less pervasive environmental and health threats.

Intervenors fault DEP for failure to undertake this remediation process years earlier before being required to do so.[30] Had DEP acted in compliance with these assertions, it would have incurred costs its consumers would have been responsible for then. So from a ratemaking perspective, this Commission's concern, the question of when the remediation should have taken place, now or in the future or twenty years ago, is not determinative of whether the costs of the remediation should be recovered through rates and to what extent. Intervenors are unable to show when DEP should have acted differently in the past or what the increased costs would have been then.[31] Indeed, whenever undertaken, the costs would have been site specific, and establishing a past cost in this case would be a near impossibility. As DEP would have been required to undertake the remediation at issue in 2015 through 2017, irrespective of other improper actions of which it has been accused and for which it pled guilty to and was sentenced for in the criminal proceeding, any disallowance in this case must be made within the context of these facts.

DEP in the past contemplated a future requirement to close unlined impoundments. While it was reasonable and appropriate to anticipate and plan for what EPA's ultimate decisions would be, the Commission determines not to penalize DEP through denial of cost recovery for its decision to wait until EPA's CCR determinations in this area were finalized. Had DEP acted prematurely in anticipation of regulations under consideration but not yet implemented, with the expenditure of substantial sums in the process, and with the ultimate EPA decisions differing from those anticipated, DEP risked unjustified expenditures. In 2015, the EPA announced the Clean Power Plan. Had electric

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[30] The Public Staff, however, was unable to classify DEP's actions or inactions as imprudence. Public Staff witness Lucas testified:

> The Public Staff is not saying that DEP's environmental noncompliance problems are the result of imprudence, because my review did not examine what Duke Energy knew or should have known about coal ash contamination at the time the ash basins were constructed. (Tr. Vol. 18, p. 340)

[31] Public Staff witness Lucas was asked what DEP should have done differently and when it should have done it. He replied:

> … I can't say exactly what year or exactly what technologies … I can't go back and tell you exactly what would have happened - - what you should have done at a certain time. I'm not sure what good it would have done for somebody to tell you, oh, 40 years ago you should have put in a clay liner at Asheville and Sutton, put in a concrete liner at the H.F. Lee plant. I mean, you just can't go back and do that kind of assessment. (Tr. Vol. 19, pp. 35-36)

AGO witness Wittliff was asked when in his opinion DEP was imprudent with respect to leachate within the impoundment leaking through the bottom into the groundwater. He responded with respect to Sutton:

> I'd have to - - I'm not sure, but I think it was 2010 or so. I don't want to be quoted on that, but I could dig through here, if you'd like. (Tr. Vol. 15, pp. 99-100)

utilities incurred costs prematurely to comply, these costs could have been called into question when the U.S. Supreme Court stayed the Clean Power Plan.

A significant example of the ambiguity and uncertainty DEP faced in the management of CCR impoundments is illustrated by reference to a November 1, 2004 Long Term Ash Strategy Study Phase Report addressing 1983 and 1984 CCR repositories at DEP's Sutton coal fired plant in New Hanover County. The 1983 impoundment was unlined and had reached capacity prior to the 2004 report. The 1984 impoundment was lined and was rapidly approaching capacity, and the report identified and classified alternatives for CCR use or disposal to prevent shutdown of the Sutton plant. In the "Problem Description" section of the report, the authoring engineer listed issues either directly or indirectly related to a contribution to the overall ash strategy for the Sutton plant. The issues were described as secondary and not a dictating factor in the solution of the best alternative but as a look at overall environmental structure and stewardship. The first issue addressed the 1983 unlined impoundment that for the most part had ceased to receive CCRs.

> <u>1983 Pond is Unlined</u>
>
> The first issue is that the 1983 ash pond was constructed during a period when it was not required to provide a non-permeable liner, and was constructed with the native sandy soils. This pond has been functionally full since 1983, but is still permitted, and is occasionally used when there are issues requiring the 1984 ash pond to be temporarily dry. The current environmental atmosphere is that these ponds will eventually have to [sic] emptied and placed in a lined containment to eliminate the leaching of the ash products into the groundwater system. This is an issue that is not currently being pressed, but it is anticipated that with the tighter environmental conditions it will soon become an emergent issue. This issue is aggravated by the fact that a test monitoring well located 300' from [sic] edge of the 1983 ash pond has shown high levels of arsenic during the past two quarterly tests. This may or may not be related to the unlined ash pond. A recent study by an independent firm indicated this concern may be less than originally thought. It could be mitigated by adding monitoring wells to the NPDES permit, but could still pose an issue in the future. There is also a county well water source approximately 1200' from the test well that is monitored by the county.

Elsewhere in the report under the "Do Nothing" alternative, the author stated:

> It is assumed that the North Carolina Division of Water Quality (NCDWQ) will require the 1983 ash pond to be emptied and lined to comply with current ash pond regulations. For the purpose of this study it is estimated that there is a 5% chance annually of the ash pond required to be relined starting 2007, and that in 2013 there will be a 10% chance annually thereafter until 2019.

In 2018, it is less than clear as to what the author refers to as the "current environmental atmosphere" or "current ash pond regulations," but the author's speculation as to if and when unlined impoundments might have to be dewatered and excavated was off the mark. The EPA's CCR rule was passed in 2015 and the NC CAMA was passed in 2014 with deadlines a number of years beyond that. DEP did not choose the alternative recommendation in the report, creation of an industrial park, nor did it excavate the unlined 1983 impoundment. The report contains no recommendation to excavate the 1983 impoundment solely for environmental remediation. The Commission is unable today to say how in the past the 1983 impoundment would have been excavated and how the excavated CCRs would be placed in a lined impoundment, what the cost would have been and what cost recovery treatment would have been appropriate. Indeed, the 1983 impoundment today is being excavated pursuant to express EPA and DEQ guidelines, and the parties to this case vigorously contest how compliance with these requirements should be accomplished and what the cost should be.

The purpose of the report was to determine the best course based upon the fact that the 1984 lined ash pond was reaching capacity and would be non-operational by June 2006. It is important to note that the author was indicating that the 1984 ash pond would be non-operational under the NPDES permit due to capacity constraints as opposed to environmental concerns.

Intervenors are advocating substantial disallowances in this case for expenditures DEP incurred to meet CAMA deadlines, such as at Sutton, before all of the regulatory requirements had been finalized. A substantial area of contention is exceedances and environmental violations addressing harmful constituents in coal ash even though determinations with respect to naturally occurring levels of background concentrations of these constituents have not been established. Rules for regulating seeps from dikes are yet to be finalized. Even as DEP continues to remediate, state regulatory agencies must review and approve the process and may impose additional restrictions, limitations and requirements. Even subsequent to EPA CCR rules and CAMA, the General Assembly enacted the MEA, changing the requirements for the Asheville plant remediation. Closure options for each of the CCR impoundments are site specific. Even now, Intervenors criticize the liners DEP has selected, asserting DEP is spending too much. Others advocate that this Commission supersede the authority of environmental regulators and require excavation of all DEP's impoundments and prohibit cap in place. The Commission is unable to recreate the past and place a price tag on remediation costs that might have been incurred in anticipation of environmental requirements.

This Commission's responsibility is cost recovery. Environmental regulators must oversee protection of the environment and public health. The Commission's responsibility is to determine whether coal ash remediation costs as required by environmental regulators should be recoverable through rates.

Another factor the Commission must address is the imposition of requirements of CAMA in addition to those of EPA. The evidence in this case is that the level of transportation costs being contested arises from more aggressive CAMA deadlines and uncertainty over the timing of the granting of regulatory permits for replacement impoundments. Except as addressed generically elsewhere, the Commission is reluctant to second-guess, with minor exception, specific DEP decisions on its attempts to comply with these requirements in a 20/20 hindsight fashion. Likewise, the Commission is reluctant, except in limited fashion, to penalize DEP for good faith efforts to comply with state statutes irrespective of the factors motivating the General Assembly to impose them.

Conversely, the Commission is unable to find DEP faultless in the dilemma it has faced. Much testimony addresses the issue of whether DEP's mismanagement of CCRs "caused" the General Assembly to enact CAMA. DEP argues that other nearby states enacted CCR remediation statutes in addition to EPA's CCR rules, and that the Dan River spill affected the timing but not the substance of CAMA's requirements. The Commission is unable to conclude that DEP mismanagement is the primary cause of CAMA. Nevertheless, the provisions of CAMA directly address remediation of DEP CCR repositories and impose accelerated deadlines with respect to them. The Commission therefore is unable to conclude that DEP mismanagement to which it admitted in the federal criminal court proceeding was not at least a contributing factor. Even DEP witness Wright's testimony suggests as much. While DEP presents persuasive evidence that its alleged mismanagement has not been supported and was not the cause of CAMA, this evidence is difficult to reconcile with its admissions and guilty pleas before the federal district court in the criminal proceeding. DEP represented that it mismanaged its CCR activities.

The Commission's conclusions with respect to the impact of DEP's mismanagement as a contributing factor to the enactment of CAMA are significant in two ways. First, the Commission determines that this conclusion adds support to the Commission's assessment of a management penalty arising primarily from the Company's admissions of mismanagement in the federal criminal case. Secondly, it supports the Commission's determination to reject more discrete disallowances such as those addressed by the Public Staff with respect to Sutton and Asheville transportation costs. The Commission deems these costs traceable to CAMA timelines, implemented in part in response to DEP's CCR management practice, but is unpersuaded that the quantification of the costs is accurate or that the severity of the proposed disallowances is justified. [32] Consequently, the Commission takes the incurrence of these costs into account in establishing the amount of its management penalty.

DEP admits to pervasive, system-wide shortcomings such as improper communication among those responsible for oversight of coal ash management. As stated above, while the Commission cannot state that CAMA would not have been passed or that its requirements other than accelerated deadlines would have been less onerous but for DEP's mismanagement of its CCR activities, neither can it state that DEP activities

[32] Witnesses Garrett and Moore supplemented their testimony to correct the quantity of CCRs located at the Sutton plant as of January 1, 2015, and adjusted the contingency time from nine months to four months given the projected completion date of excavation of March 2019 rather than October 2015. (Tr. Vol. 18, pp. 171-72, 192.)

were without impact on the CAMA provisions that have resulted in increased costs that are at issue in this case. More fundamentally, in its admissions and pleas of guilty before the federal district court, DEP has outlined acts of criminal negligence through management misfeasance. In so doing, the Commission determines that, irrespective of CAMA, DEP has placed its consumers at risk of inadequate or unreasonably expensive service.

The Commission must regulate DEP pursuant to the requirements of Chapter 62 to see that compatibility with environmental well-being is maintained. G.S. 62-2(a)(5) Service is to be provided on a well-planned and coordinated basis that is consistent with the level of energy needed for the protection of public health and safety for the promotion of the general welfare as expressed in the state energy policy, G.S. 62-2(a)(6). All companies are prevented from violating environmental statutes. G.S 143-215.1. DEP is required to maintain safe and reliable service. As an electric utility, safety usually means safe electric service. In the context of this case, the Commission also determines that it means assuring safe operation of its coal-burning facilities so as not to render the environment unsafe. Declining to acquire and install a relatively inexpensive camera in a decades-old storm water drainage pipe over which the large coal ash impoundment is constructed when engineers repeatedly recommend such installation does not comply with a duty to provide safe service.

Fortunately, Dan River was a plant where coal generation had been discontinued at the time of the 2014 spill. Risers in disrepair, inadequate oversight of impoundment dikes and seeps have not resulted in catastrophic failures causing plants to be taken offline or service disruptions, but DEP's irresponsible management of its impoundments over a discrete period of time placed its customers at risk of inadequate service and has resulted in cost increases greater than those necessary to adequately maintain and operate its facilities.

Consequently, having pled guilty to management criminal negligence, DEP cannot go without sanction in the form of cost of service disallowances. At the same time, to the extent the Dan River plant spill has contributed to the CCR remediation expense that otherwise would have been lower, the Company has borne responsibility for Dan River remediation costs without ratepayer support. The Company has been penalized by the federal district court. It cannot seek cost recovery of these monetary penalties or remediation assessments. Further, the mismanagement to which DEP pled guilty was only for a fraction of the time DEP operated the impoundments. No evidence was submitted that DEP's management was imprudent from the initial date of operation. The penalties imposed by this Commission take the form of denial of recovery of a return on historic remediation costs that reduce a portion of costs that ratepayers otherwise would have borne. The Commission deems double penalization inappropriate as an unwarranted penalty that has a tendency to unduly threaten the long-term overall well-being of the Company, a situation not in the best interest of its consumers.

A major difficulty the Commission confronts in this case is the identification and quantification of the appropriate CCR remediation adjustment to incurred costs. The record does not contain evidence appropriately quantifying the cost DEP incurred with respect to discrete remediation activities.[33] The Public Staff's witnesses' encountered difficulty in quantifying and supporting the costs for the alleged Sutton and Asheville transportation disallowances and other less specific ones motivates the Commission to resist imposition of discrete cost disallowances. The Commission deems disallowance of the totality of costs, as some parties advocate, unjustified. The Commission deems full recovery, as DEP advocates, unjustified. The Commission deems the Public Staff's 50/50 equitable sharing disallowance unfairly punitive and of questionable legal sustainability. The Commission deems requirements that more costs be imposed than DEQ might require without cost recovery unjustified. Moreover, the Commission deems it inadvisable to approve or suggest future disallowances with respect to CCR remediation expenditures as far away as 2028 and beyond. In sum, the Commission cannot agree with any of the parties in this case and must fashion and quantify a remedy different from any of those advocated before it.

The Commission operates under a legislative mandate that requires it to fix rates that will allow a utility "by sound management" to pay all of its reasonable operating costs, including maintenance, depreciation, and taxes, and earn a fair return on its investment. G.S. 62-133(b)(4). State ex rel. Utils. Comm'n v. General Telephone Co., 285 N.C. 671, 208 S.E.2d 681 (1974). If the Commission finds that a utility has not been soundly managed, it may penalize a utility by authorizing less than a "fair return." Id.[34] The Commission must quantify the penalty by making a finding of what return would have been allowed if there were sound management. Id. The North Carolina Supreme Court has stated that "[t]he size of the penalty is left to the judgment of the commission, but must be based upon substantial evidence, and the penalty must not result in a confiscatory rate of return." Id. General Telephone addressed a rate of return on rate base penalty for mismanagement resulting in inadequate service. In this case, DEP's

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[33] AGO witness Wittliff was asked whether he offered any opinion on what he thought the Company's appropriate amount of recovery under the CCR rule should be. He responded:

> … I would explain that I'd love to have been able to come up with some extremely precise numbers and explain it all to you where it all made crystal clear sense and you could hang your hat on it and that's the number, we can pin that down. The problem is, is that this is, as we've already - - everyone seems to have observed, is it's an extremely complex case with a lot of moving parts, and it's not as easy to - - to make that sort of definitive statement. (Tr. Vol. 15, pp. 77-78)

Further, AGO witness Wittliff was asked why other than for CAMA compliance he performed no dollar-for-dollar analysis. He responded: "[b]ut we just couldn't get comfortable with making a data that we would want to bring to you and say this is the number." (Tr. Vol. 15, pp. 85-86)

[34] See also State ex rel. Utils. Comm'n v. Morgan, 277 N.C. 255, 177 S.E.2d 405 (1970) (holding "that it is not reasonable to construe [the statute] to require the Commission to shut its eyes to 'poor' and 'substandard' service resulting from a company's willful, or negligent, failure to maintain its properties [] and it is obvious that consistently poor service, attributable to defective or inadequate or poorly designed equipment or construction justifies a subtraction …"

mismanagement takes the form of admitted inadequate oversight of its CCR activities that placed service to its consumers at risk and, at least indirectly, increased costs.

Consequently, the Commission in the exercise of its judgment and discretion, determines that a management penalty in the approximate sum of $30 million is appropriate with respect to DEP CCR remediation expenses accounted for in the earlier established ARO with respect to costs incurred through the end of the test year as adjusted. This penalty is based on the totality of evidence contained in the record, as recited in detail above, and does not result in confiscation. Had the Commission not imposed this penalty, the ARO costs would have been amortized over five years with a full authorized return on the unamortized balance. The penalty will be imposed by reducing the resulting annual revenue requirement by $6 million (from the return on the unamortized balance in the rate base portion) for each of the five years, resulting in an approximate $30 million management penalty. While this penalty differs in form from that in <u>General Telephone</u>, the Commission determines that conceptually <u>General Telephone</u> provides appropriate precedent. By imposing this management penalty, the Commission does not suggest that further penalty or disallowances with respect to past DEP actions or inactions will be imposed with respect to future CCR remediation expenses. The size of the penalty meets judicial requirements as it is quantified and is not confiscatory.

With respect to CCR remediation costs to be incurred during the period rates approved in this case will be in effect, the Commission determines that the “run rate” or the “ongoing compliance costs” mechanism advocated by DEP will not be approved. By requesting the creation of an ARO, in addition to the run rate, DEP concedes that treating CCR expenditures as a recurring test year expense is inadequate. Future annual costs, the evidence shows, are predicted to vary substantially from year to year. Instead, CCR remediation costs incurred by DEP during the period rates approved in this case will be in effect shall be booked to an ARO that shall accrue carrying costs at the approved overall cost of capital approved in this case (the net of tax rate of return, net of associated accumulated deferred income taxes). The Commission will address the appropriate amortization period in DEP’s next general rate case, and, unless future imprudence is established, will permit earning a full return on the unamortized balance. While this ratemaking treatment will, in limited fashion, diminish the quality of DEP’s earnings, over time, assuming reasonable and prudent CCR management practices, it permits appropriate recovery.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 57-59

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

In his direct testimony, DEP witness Fountain stated that although costs related to beneficial reuse are included in DEP's base rate case, the Company believes that certain amounts are more appropriately recovered through the fuel clause. (Tr. Vol. 6, p. 39 n.1.)

Witness Bateman testified that of the $260.3 million expected deferred balance, $15.1 million, $13.8 million of spend and $1.3 million of return, is related to 2017 beneficial reuse projected costs. As noted by witness Fountain, witness Bateman stated that these amounts are included in the Company's request, but DEP believes that these costs are more appropriately recovered through the annual fuel rider. Witness Bateman explained that if the Commission approves the fuel rider treatment requested by the Company, DEP will remove $15.1 million from the deferred balance in this adjustment. (Tr. Vol. 6, pp. 122-23.)

In her direct testimony, Company witness McGee testified that the beneficial reuse of CCR constitutes a sale of a by-product produced in the generation process, and, therefore, associated gains or losses on the sale should be included in the fuel adjustment clause under G.S. 62-133.2 (a1)(9). (Tr. Vol. 10, p. 104.) According to witness McGee, a sale has occurred when the title to a by-product is transferred to a third party, and the by-product, having value to the third party, will be beneficially reused. (Tr. Vol. 10, pp. 104-05.) In this particular case, the amounts for which the Company is requesting recovery represent a net loss on the sale of CCR that is to be used as structural fill, which is a beneficial reuse. She testified that the particular transaction, as further discussed in witness Kerin's testimony, involves the sale of CCR produced at DEP's Sutton coal plant, and therefore the input to the by-product is the coal that has been burned at Sutton to produce generation. Thus, she contended that such coal burned has been and continues to be a "fuel or fuel-related cost" under the fuel clause statute as described above. Witness McGee testified that a sale of a by-product is different than disposal of a by-product in that the disposal of a by-product may involve some movement of the by-product and/or transfer of title, but there is no reuse or alternative use of the by-product. According to witness McGee, for transactions that the Company considers to be a sale, the by-product's intrinsic value is recognized in the reuse of the by-product. (Tr. Vol. 10, p. 105.) Finally, witness McGee cited certain statements of the Commission in a 2016 Commission Report to the North Carolina General Assembly[35] (Commission Report) regarding incremental cost incentives related to CCRs, filed in Docket No. E-100, Sub 146, as supportive of the Company's position that beneficial reuse constitutes a sale under the fuel adjustment clause. (Tr. Vol. 10, pp. 105-06.)

Company witness Kerin testified that DEP is now selling excavated ash for reuse in the Brickhaven mine reclamation project, a large scale, fully-lined, beneficial reuse project in Moncure, North Carolina. (Tr. Vol. 16, p. 116.) He testified that he agreed with Company witness McGee that the certain beneficial reuse costs are more appropriately recovered through fuel clause proceedings. According to witness Kerin, coal has been used as the fuel to produce power at DEP's Sutton plant. A by-product of that process is

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

CCR. As a means to handle that by-product, CCR is sold to the Brickhaven mine to be used as structural fill, which is a beneficial reuse. (Tr. Vol. 16, p. 117.)

Public Staff witness Lucas testified that the costs relating to the disposal of CCR at Brickhaven, to the extent they are reasonable and prudent, should be recovered in base rates and not through the fuel adjustment clause because the costs did not result from the sale of CCR. (T Vol. 18, p. 230.) Witness Lucas provided background regarding the Charah transaction at issue. He testified that Brickhaven is a former clay mine consisting of 333.55 acres located in Chatham County, North Carolina. By Special Warranty Deed recorded on November 13, 2014, Green Meadow, LLC, a wholly owned subsidiary of Charah, purchased Brickhaven from General Shale Brick, Inc. On June 5, 2015, Green Meadow, LLC, and Charah received a permit from DEQ to construct and operate Brickhaven as a "Solid Waste Management Facility, Structural Fill, Mine Reclamation". (Tr. Vol. 18, p. 231.) Charah is a Kentucky-based company, and according to its website, it "is the largest privately-held provider of coal combustion product (CCP) management for the coal-fired power generation industry in the U.S."[36] In its Limited Petition to Intervene in this case, Charah stated that it is a contractor of DEP and is engaged in the remediation of CCR from one or more DEP facilities. (Tr. Vol. 18, p. 19.)

Witness Lucas explained that in July of 2014, Duke Energy Business Services, LLC (DEBS), on behalf of DEC and DEP, issued a bidding event for the excavation, transportation, and off-site storage of the full volume of CCR at four sites: Riverbend, Dan River, and Sutton in North Carolina and W.S. Lee in South Carolina. On October 3, 2014, DEBS opened a bidding event for the Phase 1 work activity (excavate, transport, and place off-site) ash at Dan River, Sutton, and W.S. Lee. Bids were solicited from three bidders, including Charah. Bids were received on October 9, 2014 (six days later). DEBS selected Charah to provide the services at the Sutton Plant. (Tr. Vol. 18, p. 232.) The purchase of CCR at the plants was not included in the scope of activities for the bidding events; both bidding events requested fixed price proposals to excavate, transport, and store coal combustion residuals from the plants. (Tr. Vol. 18, p. 233.)

Witness Lucas described the contractual arrangement between DEBS and Charah regarding the removal of CCR from the Sutton Plant. He stated that DEBS, as agent for DEP and DEC, and Charah entered into Master Contract 8323 (Master Contract) dated November 12, 2014, for the Phase 1 Excavation Work at the Riverbend and Sutton Plants. Charah is referred to as the "Seller" or "Contractor" in the Master Contract. Charah is not referred to as a "Buyer". The Master Contract defined the type and scope of work, terms and conditions, pricing, and invoicing. The Master Contract contemplated the issuance of subsequent Purchase Orders as written authorization to proceed with the scope of work identified in the Purchase Order. The Sutton Phase 1 Work Scope was set forth in Exhibit D-2 of the Master Contract. It included the installation of haul roads, engineering the development of a rail loading system, erosion and sedimentation control, and dewatering, ash pond excavation, transportation, unloading, and placement. The Seller's (i.e.,

[36] http://charah.com

Charah's) Pricing Schedule was set forth as Exhibit E. The Pricing Schedule included both fixed pricing and per ton pricing. Witness Lucas testified that the fixed pricing was for mobilization, site preparation, erosion, and sedimentation control work. The per ton pricing was for excavation, loading and transportation, unloading, development, placement, home and field office overhead, and profit. (Tr. Vol. 18, pp. 233-34.) DEBS and Charah entered into Purchase Orders authorizing Charah to transport CCRs from Sutton by truck to Brickhaven and then to construct and transport CCRs by rail to Brickhaven. Purchase Order 1107196 constituted the vast majority of the excavation, transportation, and disposal work for Sutton, and 20 change orders were executed for this Purchase Order. (Tr. Vol. 18, pp. 234-35.)

Witness Lucas testified that nothing in the bid documents, contracts, purchase orders, or change orders for the Sutton Plant produced in discovery assign any value to the CCR to "net" against the cost of the services provided by Charah. (Tr. Vol. 18, pp. 235-36.) When asked to provide all documents that show how the Company or Charah calculated the "net value" or discount value of CCR when setting the cost of services provided by Charah, the Company responded that it had no responsive documents. In addition, when asked how much Charah paid the Company for the Sutton CCR, the Company responded that "there is not a defined price in the operative documents for the Sutton ash." (Tr. Vol. 18, p. 236.)

Witness Lucas testified that DEP and Charah knew how to assign a value to CCR in a sale, as demonstrated by the Master By Product Marketing, Sales, and Storage Agreement (Agreement) entered into by DEC, DEP, and Charah in December of 2013, and associated Work Orders, which obligated Charah to purchase CCR from DEP or DEC, as applicable, at a price as set forth in the Work Orders. This Agreement formed the basis for the sale of CCR at the Belews Creek and Marshall plants via Work Orders entered into by DEC and Charah on January 1, 2014. (Tr. Vol.18, p. 236.)

Witness Lucas asserted that the specific provisions relating to the services and pricing in the Master Contract, Purchase Orders, and change orders for Sutton all support the conclusion that the arrangement was one for Charah to provide ash disposal services to DEP, not for a sale of DEP's CCR to Charah. Although one of the general provisions of the Master Contract stated that the services to be performed by Charah constituted payment by Charah for the CCRs, DEP has admitted that there was no defined price for the CCRs and no documentation showing that the parties assigned any value at all to the CCRs. (Tr. Vol. 18, pp 236-37.) As a result, witness Lucas concluded that the specific provisions of both the Master Contract and Purchase Orders overwhelmingly point to a contract for services, not a sale.

Witness Lucas also addressed the findings in the Commission Report cited by Company witness McGee as support for DEP's position. He testified that the findings in the Commission Report do not support DEP's conclusion that the costs of the beneficial reuse of CCR are recoverable through the fuel clause. The General Assembly in the legislation directed the Commission to specifically address in its report "possible revisions to the current policy on allowed incremental cost recoupment that would promote reprocessing and other technologies that allow the reuse of coal combustion residuals stored in surface impoundments for concrete and other beneficial end uses". The Commission's Report examined the statutory framework for cost recovery and concluded that current policies and practices are adequate to encourage reuse of CCRs for concrete and other beneficial end uses. However, as recognized by the Commission in the Report, recovery through the fuel clause presupposes that there is a sale. On page 13 of the Report, the Commission stated, "Customers' rates are adjusted annually to include profits or losses associated with efforts to sell CCRs for beneficial reuse." On page 14 of the Report, the Commission recognized that "sales of CCRs typically result in immediate net costs to ratepayers." The Commission did not conclude in its Report that the costs of processing CCRs for beneficial use, without a sale, are recoverable in the fuel clause. (Tr. Vol. 18, pp. 237-38.)

Finally, witness Lucas addressed the fact that the Commission has allowed the Company to recover net gains or losses from the sale of CCRs through the Company's annual fuel rider. Witness Lucas stated that if there is an actual sale of CCRs, cost recovery through the fuel clause may be appropriate, if the costs are reasonably and prudently incurred. Where, however, there is a contract for services not involving a sale of CCRs, costs arising from that contract should not be recoverable through the fuel clause. Witness Lucas concluded that the true purpose of moving CCRs from Sutton to Brickhaven is environmental remediation and the disposal of CCRs, and not the sale of a byproduct. (Tr. Vol. 18, pp. 238-39.)

In her rebuttal, Company witness McGee disagreed with witness Lucas' characterization of the contractual arrangement with Charah involving the movement of ash from the Sutton Plant to Brickhaven. She asserted that DEP was compensated for the value of the CCRs. She explained that under the arrangement, the compensation to DEP was expressed indirectly through the values agreed to on other terms and conditions in the contract. In other words, the cost of services provided by Charah would have been higher without the sale of the CCRs from Duke Energy to Charah. She further asserted that the CCRs had value to Charah in that it was used in a process as a substitute for an alternative material. Without the purchase of the CCRs, Charah would have needed to procure topsoil or another material to use as structural fill, an added cost that Charah was able to avoid. She concluded that the overall economics of the sales agreement therefore reflected the intrinsic value of the CCRs. (Tr. Vol. 10, p. 111.)

Witness McGee identified two provisions of the Master Contract in support of her position. First, per Section 3 of Exhibit B to the Master Contract (Exhibit B), the Company transferred title to, risk of loss of, and responsibility for the CCRs to Charah once the CCRs is loaded in to truck or railcar at Sutton for transportation to Brickhaven. According to witness McGee, this provision indicates that the CCRs had value to the parties that had to be transferred through title. Further, the fact that Charah agreed to accept the transfer of title and risk of loss at the point that the CCRs was loaded onto its trucks or rail cars for delivery is strong evidence that the CCRs had transferable value. (Tr. Vol. 10, p. 112.)

Witness McGee also cited Section 4.2 of Exhibit B in support of the Company's position, which provides in pertinent part that, "payment of the Service Fee by Duke Energy to Contractor . . . together with any Ash that is transferred by Duke Energy, to Contractor under the applicable Purchase Order, constitutes payment in full, by Duke Energy to Contractor for any and all of contractor's costs to perform the Services...." Witness McGee asserted that this section clearly acknowledges that the CCRs serve as partial consideration for the services rendered by Charah. She stated that it was therefore understood and accepted by both parties that the service fee charged by Charah for its services was offset by the value of the CCRs to Charah, thereby constituting a sale. (Tr. Vol. 10, p. 112.)

Witness McGee also took issue with witness Lucas' characterization of the arrangement as a "disposal". She stated that the CCRs at Sutton were not thrown away or placed in a landfill, but replaced the topsoil that would have been used as structural fill in the reclamation of the Brickhaven mine. Further, she noted that the EPA definition of beneficial reuse is "the reusing of a material in a manner that makes it a valuable commodity, such as use in a manufacturing process or as a structural fill." Based on the EPA definition, witness McGee maintained that the use of the Sutton CCRs as structural fill for the Brickhaven mine indicates that the CCRs were a valuable commodity. (Tr. Vol. 10, p. 113.)

Witness McGee also cited Section 2.1 of Exhibit B, which states, "[t]he Parties desire that Contractor excavate certain quantities of Ash from the Ash Ponds or Onsite Storage, transport such Ash off the Station property for resale to Contractor for beneficial reuse in the production of construction products, as an engineered structural fill and/or for closure of a mine reclamation projects, etc. . . ." (emphasis added). She asserted that both parties clearly contemplated and agreed upon the use of the CCRs, which is expressed in the contract. Accordingly, the purpose of this transaction was the sale of CCRs produced at the Company's Sutton coal plant to Charah for beneficial reuse at Brickhaven. (Tr. Vol. 10, pp. 113-14.)

Finally, witness McGee testified that the Company has included the gain/loss of CCRs in the fuel adjustment clause in the past. Specifically, she noted that the losses on the sale of CCRs from the Asheville plant to the Asheville Airport as structural fill have been included in the fuel adjustment clause since 2008. (Tr. Vol. 10, p. 114) She noted that the Master Contract had the same language as that used for the CCRs from the Asheville Plant, and that the sale of the CCRs was implied since both parties agreed that both the value of the CCRs and the additional funds paid by Duke would constitute full payment for the work as outlined in the associated purchase order. (Tr. Vol. 10, p. 115.)

During cross-examination, Company witness McGee admitted that no particular projects or costs are presented in the Company's fuel filings and that the Commission only approves an overall number in the fuel rates. (Tr. Vol. 10, p. 130.) Further, the Commission did not specifically review or consider the Asheville CCR sale in prior fuel proceedings. (Tr. Vol. 10, p. 131.) She testified that the cost of disposing of CCRs in a landfill would not be a sale and would not be recoverable under the fuel clause. (Tr. Vol.

10, p. 133.) A series of exhibits were introduced (Public Staff [PS] McGee Cross-Examination Exhibits 1-5), which were Company responses to Public Staff data requests. (Tr. Vol. 10, pp. 134-43.) In these data requests, the Public Staff asked the Company to describe in detail and provide documentation in support of its assertion that the transaction between Charah and the Company constitutes a sale of CCRs. When asked to cite the specific language in the contracts and amendments between DEP and Charah that support the Company's assertion, the Company cited Sections 4.1 and 4.2 of Exhibit B of the Master Contract. (Tr. Vol. 10, Public Staff McGee Cross-Examination Exhibit 2.) When asked, "How much did Charah pay the Company for the Sutton coal ash?," the Company responded that "there is not a defined price in the operative documents for the Sutton ash." Further, when asked to provide all documents that show how the Company or Charah calculated the "net value" of or discount value of coal ash when setting the cost of services provided by Charah, the Company responded that it did not have any responsive documents. (Public Staff McGee Cross-Examination Exhibit 4.)

In Public Staff McGee Cross-Examination Exhibit 5 (Company response to Public Staff Data Request No. 174-1), the Public Staff asked the Company to provide documentation supporting witness McGee's assertion in her rebuttal that "without the purchase of the coal ash, Charah would have needed to procure topsoil or another material to use as structural fill, an added cost that Charah was able to avoid". The Public Staff also asked for information and documentation that shows what Charah would be constructing at the Brickhaven site that requires the use of structural fill. In response, the Company stated that it does not have the requested documentation but is aware that Charah is using the CCRs as structural fill; further, it has no documentation related to Charah's future plans at its Brickhaven mine. (PS McGee Cross Examination Exhibit 5) On further cross-examination, witness McGee did not dispute that the deed to Brickhaven was recorded the day after the Master Contract was signed. She also admitted that managing CCRs is Charah's expertise. (Tr. Vol. 10, p. 144.) Further, witness McGee acknowledged that it was necessary for the Company to pay Chatham County millions of dollars to send the Sutton CCRs to Brickhaven, as demonstrated by portions of a Settlement Agreement between DEP, DEC, and Chatham County dated June 22, 2015, that were read into the record. (Tr. Vol. 10, pp. 145-47.) Regarding Section 3 of Exhibit B, in which the Company transferred title to, risk of loss of, and responsibility for the CCRs to Charah once the CCRs are loaded in to truck or railcar at Sutton for transportation to Brickhaven, witness McGee acknowledged that the provision could also refer to the transfer of liability for the CCRs. (Tr. Vol. 10, p. 150.)

During the confidential portion of witness McGee's cross-examination, several contracts were entered into the record. Public Staff McGee Confidential Cross-Examination Exhibit 6 is the Master Contract, dated November 12, 2014, between Charah and DEBS on behalf of DEP and DEC for the Phase 1 Excavation Work at Riverbend and Sutton and is the Master Contract discussed in witness McGee's and Public Staff witness Lucas' testimony. The costs relating to this contract are what the Company seeks to recover through the fuel clause. (Confidential Tr. Vol. 10, pp. 152-53.) In the Master Contract, Charah is listed as the "Seller". (Confidential Tr. Vol. 10, p. 152.) Exhibit E of the Master Contract contains the pricing schedule for the Master Contract, including pricing for items such as site preparation, excavation, loading and transportation, unloading, development, home or field office overhead and profit, but no pricing for Charah's purchase of the CCRs. (Confidential T 10, pp 153-54) This was the pricing applicable for sending the ash to Brickhaven, as noted in Footnote 1 on page E-2. (Confidential Tr. Vol. 10, p. 154.) The Master Contract also had alternative pricing in the event the CCRs could not be transported to Brickhaven and instead had to be transported to the Anson County Landfill. (Confidential Tr. Vol. 10, p. 154) Witness McGee testified that if this alternative had been used, the costs associated with the Master Contract would not be recoverable under the fuel adjustment clause. (Confidential Tr. Vol. 10, p. 154.)

Public Staff McGee Confidential Cross-Examination Exhibit 7 is Master Contract 8324 dated November 12, 2014, between Waste Management National Services, Inc. (Waste Management), and DEBS on behalf of DEC for the Phase 1 Excavation Work at Dan River and W.S. Lee. The Master Contract and the Waste Management Master Contract 8324 are both dated November 12, 2014. (Confidential Tr. Vol. 10, p. 159.) The Waste Management Master Contract 8324 contains pricing schedules similar to those in the Master Contract. Under the Waste Management Master Contract 8324, the CCRs from Dan River was to be transported to the Maplewood Landfill Site, and the CCRs from W.S. Lee was to be transported to the R&B Landfill Site in Homer, Georgia. The Waste Management Master Contract 8324 includes the same language used in the Master Contract, i.e., "payment of the Service Fee by Duke Energy to Contractor . . . together with any Ash that is transferred by Duke Energy, to Contractor under the applicable Purchase Order, constitutes payment in full, by Duke Energy to Contractor for any and all of contractor's costs to perform the Services..." Witness McGee testified that the costs associated with the Waste Management Master Contract 8324 should not be recoverable under the fuel clause. (Confidential Tr. Vol. 10, pp. 159-60.)

Public Staff McGee Confidential Cross-Examination Exhibit 10 is Purchase Order 1380566 dated September 25, 2015, authorizing Waste Management to transport CCRs from the Asheville Plant for disposal at R&B Landfill in Homer, Georgia. (Confidential Vol. Tr. 10, p. 161.) On page 4 of this Purchase Order, it states that the terms and conditions of Master Contract 8324 govern the work. (Confidential Tr. Vol. 10, p. 162.) Witness McGee testified that the costs associated with the Purchase Order would not be eligible for recovery under the fuel adjustment clause. (Confidential Tr. Vol. 10, p. 163.)

Public Staff McGee Confidential Cross-Examination Exhibit 8 is a Master Contract dated December 15, 2016, between Trans Ash, Inc. and DEBS on behalf of DEP and other Duke Energy entities for "Ash Project Services." Public Staff McGee Confidential Exhibit 9 is Master Contract dated March 14, 2017, between Parsons Environment & Infrastructure Group, Inc. and DEBS on behalf of DEP and other Duke Energy entities for "Ash Project Services".

All four Master Contracts include as Exhibit B the "Duke Energy Standard Terms and Conditions for Ash Services as Agreed upon By Seller and Duke Energy", and contain the same or substantially similar language in Sections 3, 4.1, and 4.2. This is the language the Company cites in support its claim that the costs associated with the Master Contract should be recoverable under the fuel adjustment clause. (Confidential Tr. 10, pp. 164-65) In response to a request by the Commission, the contract between Charah and Progress Energy, Inc., dated June 18, 2007, for the excavation, transportation, and resale of ash from the Asheville Plant to the Asheville Regional Airport Authority (Asheville Contract) was filed by DEP as Confidential Late Filed Exhibit 3. Section 5.1 of the Asheville Contract provided that the work performed by Charah constituted payment for the CCRs.

During the cross-examination of Company witness Kerin on his direct testimony, two exhibits were introduced. Public Staff Kerin Cross-Examination Exhibit 1, an excerpt (with confidential portions removed) of an Executive Summary, summarized the process undertaken to select the vendors to excavate the CCRs at Sutton, as well as Dan River, W. S. Lee, and Riverbend. (Tr. Vol. 17, p. 40.) The document describes the bidding events that took place and the bid evaluation process. Bids were evaluated based on technical and commercial criteria, including the bidder's acceptance level of Duke Energy Terms and Conditions. (Tr. Vol. 17, p. 42.) The document also describes the key contract provisions that would apply to the work, regardless of disposal method. (Tr. Vol. 17, pp. 42-43.) Included in the key contract provisions was a requirement that the work be completed under the Duke Energy Standard Terms and Conditions for Ash Reclamation and Placement. (Tr. Vol. 17, p. 43.)

Public Staff Kerin Cross-Examination Exhibit 2 is a memorandum (Subject: Addendum Number 1) dated October 17, 2014, from Joseph Frondorf of Duke Energy Corporation to the bid teams for the bidding event summarized in Public Staff Kerin Cross-Examination 1. (Tr. Vol. 17, pp. 43-44.) Attached to the memorandum was Duke Energy's Standard Terms and Conditions for Ash Reclamation and Placement, discussed in the Executive Summary as a key contract provision and ultimately incorporated in the contracts (as Exhibit B) with Charah for Sutton and Riverbend and Waste Management for Dan River and W. S. Lee. (Tr. Vol. 17, pp. 44-45.)

In its post-hearing Brief, NC WARN contends that the use of CCRs at Brickhaven is not a "beneficial use," citing the ruling of a Superior Court revoking state permits allowing CCRs to be used as mine reclamation in areas not already mined or otherwise excavated.

Discussion and Conclusion

DEP seeks to recover certain CCR costs related to the excavation and movement of CCRs from the Sutton Plant in Wilmington, North Carolina to the Brickhaven facility in Chatham County, North Carolina, through the fuel adjustment clause on the grounds that the beneficial reuse of CCRs constitutes a sale of a by-product produced in the generation process. The fuel adjustment statute, G.S. 62-133.2, allows electric public utilities to recover through an annual rider certain fuel and fuel-related costs. G.S. 62-133.2(a1)(9) provides:

> Cost of fuel and fuel-related costs shall be adjusted for any net gains or losses resulting from any sales by the electric public utility of by-products produced in the

generation process to the extent the costs of the inputs leading to that by-product are costs of fuel or fuel-related costs.

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

This is the first case in which the Commission has been squarely presented with this issue. The Company contends that the fact that the Commission approved recovery of costs through the fuel adjustment clause related to a similar contractual arrangement between Charah and DEP to remove CCRs from the Asheville Plant and transport it to the Asheville Airport demonstrates that the costs related to the Master Contract are also similarly recoverable. The Commission disagrees. Nothing regarding the Asheville contractual arrangement was specifically presented by the Company, the Public Staff, or any other party in the Company's relevant fuel filings, and, therefore, the present issue was not specifically considered by the Commission. Consequently, the fuel factors approved by the Commission that included the Asheville transaction costs do not constitute specific approval of the transaction as a "sale of a by-product" and do not preclude the Commission from considering this issue now.

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

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

The Company relies on the existence of three provisions in Exhibit B of the Master Contract in support of its contention that a sale of CCRs occurred. Company witness McGee states in her testimony that per Section 3 of the Master Contract, the Company transferred title to, risk of loss of, and responsibility for the CCRs to Charah once the CCRs wre loaded in to truck or railcar at Sutton, indicating the CCRs had value. However, on cross-examination, she agreed that this language could be interpreted to mean the transfer of liability for the CCRs. This interpretation – that transfer of title relates to the transfer of liability - is supported by the language in the second sentence of Section 3, which states that the Contractor is not assuming any responsibility for any liabilities arising out of or relating to the creations, existence, storage, or handling of the ash prior to the time title to the ash passes to Contractor. In addition, the Scope of Work Clarification provided to the bidders of the Sutton project and attached to PS Kerin Cross-Examination Exhibit 2, page 2, states, under paragraph 6, "Once the ash is loaded into the transport vehicle, liability of shall transfer to the bidder, and shall remain with the bidder unless it is transfer (sic) to the owner of the final ash storage location." (emphasis added) The Commission finds and concludes that Section 3 of the Master Contract does not support a finding that the Sutton CCRs had value. On the contrary, the balance of this evidence supports the conclusion that possession of the CCRs represented a liability, not an asset.

The Company also cites Sections 4.1 and 4.2 of Exhibit B of the Master Contract, which in essence state that the services performed by Charah constitute payment for the CCRs. The Commission is not persuaded that inclusion of these provisions demonstrate that a sale of CCRs occurred. These provisions are part of the Duke Energy Standard Terms and Conditions for Ash Reclamation and Placement that have been included in other contracts for CCR services, regardless of the type of service and disposal method. PS McGee Confidential Cross-Examination Exhibit 7, the master contract for the Phase 1 Excavation Work at Dan River and W. S. Lee, contain the same provisions and pricing schedules similar to the Master Contract, and witness McGee admitted that the costs incurred under that contract should not be recoverable under the fuel clause, as the CCRs were landfilled. The Commission finds that these provisions are boilerplate that do not support the conclusion that a sale of the Sutton CCRs occurred.

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

As noted at the beginning of this discussion, DEP witness Bateman testified that of the $260.3 million expected deferred CCR cost balance, $15.1 million -- $13.8 million of spend and $1.3 million of return -- is related to 2017 Charah projected costs. Witness Bateman explained that if the Commission approves the fuel rider treatment requested by the Company, DEP will remove $15.1 million from the deferred balance in this adjustment. (Tr. Vol. 6, pp. 122-23.) The Commission having denied the recovery of the $15.1 million Charah costs in fuel rates, the recovery of this $15.1 million is left in DEP's $260.3 million deferred CCR balance for consideration of recovery in DEP's base rates.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 60

The evidence supporting this finding of fact and conclusion can be found in the Application, Form E-1, the testimony of Company witness Wright, and the testimony of Public Staff witnesses Lucas and Maness.

Public Staff witness Maness stated that CCR costs prudently incurred from January 2015 through August 2017 (i.e., costs not subject to Public Staff recommended disallowances apart from equitable sharing) should be allowed provisional cost recovery. (T Vol. 19, p. 303) He explained that the reasonableness of some of those costs may depend on the outcome of legal proceedings or other legal determinations, as described by witness Lucas. (Id.) Witness Lucas described how past actions of DEP may be determined to be violations in the future with respect to both ongoing review by DEQ and pending litigation. These circumstances affect the ability of the Public Staff and other parties to recommend disallowances for specific costs because an environmental violation must be established before there is any decision on whether to disallow the cost of remedying the violation.

In particular, witness Lucas noted that DEQ is still in the process of deciding which unauthorized seeps will be allowed under renewed NPDES permits and which will require some other action by DEP. (Tr. Vol. 18, pp. 253-54.) He stated in testimony prefiled in October 2017 that DEQ and DEP expected to reach consensus on provisional background threshold values for constituents of interest, meaning that the number of groundwater exceedances that are actual violations would not be known until then. (Tr. Vol. 18, pp. 254, 256.) He further stated that monitoring data to determine compliance with, and violations of, the CCR Rule standards would not be available until January 2018. (Tr. Vol. 18, p. 254.) In supplemental testimony, witness Lucas was able to update the groundwater violations of the 2L regulation. (Tr. Vol. 18, p. 290; Revised Lucas Exhibit 6) In addition, the Public Staff noted that there are pending lawsuits against DEP regarding the Mayo and Roxboro plants that allege violations of environmental laws. (Tr. Vol. 18, pp. 260-62.) The outcome of these lawsuits will affect how much DEP must spend for corrective action, and whether associated litigation costs should be deemed reasonable.

Witness Wright disagreed with the Public Staff's recommendation of provisional cost recovery for coal ash expenditures prudently incurred from January 2015 through August 2017, based on the argument that the appropriateness of such recovery may depend on the outcome of legal determinations. He noted first that this would appear to be retroactive ratemaking. He also stated that the standard is that the utility makes the best possible decisions on expenditures based on the information available at the time, and determinations of the reasonableness and prudency of these costs should not depend on future outcomes of legal proceedings but what was known or knowable at the time. (Tr. Vol. 20, pp. 165-66, 178.)

Provisional cost recovery is appropriate in certain circumstances. However, the Commission is not persuaded that there is good cause to order provisional cost recovery of DEP's CCR costs that are approved in this Order. The Commission has weighed the Public Staff's and other intervenors' concerns about the pending insurance lawsuits and pending determinations by DEQ, EPA, and certain courts, that will establish whether past actions of DEP amount to environmental violations against the uncertainty that is inherent in provisional rates. With regard to the insurance litigation, DEP has committed that insurance proceeds recovered by DEP will benefit ratepayers as an off-set to DEP's CCR costs. Further, the insurance proceeds are not known and measurable as of the end of the test year. Moreover, the Commission has included in this Order specific reporting requirements and other conditions with which DEP must comply regarding the insurance proceeds.

With respect to pending determinations by EPA and DEQ, the Commission is not inclined to delay its work in order to wait for these agencies to complete their work. As a result, on balance the Commission finds and concludes that it will not order that the CCR cost recovery in this docket is provisional.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 61-62

The evidence supporting these findings of fact and conclusions can be found in the Application, Form E-1, the testimony of Company witnesses Kerin and Bateman, and the testimony of Public Staff witness Maness.

CAMA Costs Identified by DEP as North Carolina Only

Witness Maness recommended two adjustments to the jurisdictional allocation factors used by the Company to allocate system-level CCR costs to the North Carolina retail jurisdiction. The first such adjustment was to allocate the costs DEP identified as "CAMA-only" costs by a comprehensive allocation factor, rather than DEP's proposed factor, which did not allocate costs to the South Carolina retail jurisdiction. Company witness Bateman stated in her testimony that there is a small portion of CCR management costs that under CAMA that are unique to North Carolina and appropriate for direct assignment to North Carolina. Company witness Kerin stated that these costs include groundwater wells used specifically for CAMA purposes and permanent water supplies provided to North Carolina customers pursuant to North Carolina law. Consequently, the Company utilized North Carolina retail allocation factors for its CAMA-only costs that did not allocate any of the system level costs to South Carolina retail operations. However, witness Maness stated that even though some of the costs incurred by DEP are being incurred pursuant to North Carolina law, it is still fair and reasonable to allocate those costs to the entire DEP system because the coal plants associated with the costs are being or were operated to serve the entire DEP system. (Tr. Vol. 18, pp. 305-06.)

In rebuttal, Company witness Bateman testified that in general she agreed with witness Maness that the costs of a system should be borne by all of the users of the system. However, she stated that the Company had identified very specific cost categories, groundwater wells used specifically for CAMA purposes and permanent water supplies provided to North Carolina customers pursuant to North Carolina law, and that they should be treated as an exception to this general rule, due to their nature as being unique to North Carolina. She stated that this unique treatment would be consistent with other examples where the Commission had allowed direct assignment to North Carolina, including the incremental costs associated with the North Carolina Renewable Energy and Energy Efficiency Standard (REPS) and the costs to comply with the North Carolina Clean Smokestacks Act. (Tr. Vol. 6, pp. 142-43.)

After consideration of this issue, the Commission finds and concludes that the adjustment recommended by Public Staff witness Maness to allocate all system-level CCR costs by a comprehensive allocation factor produces a more reasonable and appropriate outcome than the proposal by the Company to allocate a portion of these costs in a manner that does not allocate them to the South Carolina retail jurisdiction. Although the costs in question were required pursuant to North Carolina law, the costs are inherently related to the burning of coal to provide electricity to the entire DEP system, including the South Carolina retail jurisdiction. The fact that these particular costs are associated with plants that are geographically located in North Carolina is no more relevant with regard to the proper allocation of these costs than it is to the proper allocation of other costs, such as fuel expense and other variable O&M expenses, which are allocated to the entire DEP system.

Further, the Commission concludes that these CAMA compliance costs are distinguishable from the examples of REPS and Clean Smokestacks costs cited by the Company. With regard to REPS costs, it is important to note that those costs are by their very nature in excess of the normal level of costs that would otherwise need to be incurred to provide an equivalent amount of energy to the Company's customers. Thus, it is appropriate that the Commission allocates the REPS costs to North Carolina customers. With regard to Clean Smokestacks costs, the Commission notes that those costs were closely related to a rate freeze that was instituted by the General Assembly for North Carolina retail purposes. However, the legislature could not require a similar freeze to be established with regard to South Carolina retail customers.

<u>CCR Cost Allocation Factors</u>

The second adjustment recommended by witness Maness to the jurisdictional allocation factors used by the Company to allocate system-level CCR costs to the North Carolina retail jurisdiction is to allocate all CCR expenditures by the energy allocation factor, rather than the demand-related production plant allocation factor, as recommended by DEP. Witness Maness testified that he recommended this change because the CCR costs are being incurred because CCRs were produced by the burning of coal to produce energy over the years and, like the cost of coal, should be allocated by energy, and not peak demand. Therefore, according to the Public Staff the energy allocation factor should be used to determine the North Carolina retail portion of these costs. (Tr. Vol. 18, p. 306.)

In rebuttal, DEP witness Hager testified that the costs in question are associated with compliance with federal and state environmental requirements related to closing CCR basins. She stated that residual end of life costs typically and logically follow the cost of the plant, which is allocated based on demand, and that end of life costs (removal costs) and salvage values are factored into depreciation rates, which are allocated based on demand, as they were in the most recent DEP general rate case. Additionally, witness Hager testified that use of the demand-related factor is consistent with end-of-life nuclear fuel costs in nuclear decommissioning costs. (Tr. Vol. 10, pp. 289-90.)

At the hearing, witness Maness was asked several questions by the Commission and by counsel for DEC regarding his recommendation, particularly how it compared to the allocation methods used for spent nuclear fuel storage. In summary, witness Maness responded that the allocation methods used for nuclear fuel could differ based on the stage of life the fuel is in. When the fuel itself is consumed, it is allocated according to energy. He stated that when it is in a state of interim storage, it may be allocated by different factors, but the portion of interim storage costs embedded in nuclear decommissioning expense is allocated by demand; and the costs paid for permanent storage, to date have largely been allocated on an energy basis. (Tr. Vol. 19, pp. 81-82.)

In its post-hearing Brief, CIGFUR maintains that DEP's proposal to allocate CCR costs based on demand is appropriate. CIGFUR states that CCR, unlike coal, has no energy potential, is not a fuel, and its cost is not recoverable through the fuel clause. (Tr. Vol. 18, p. 363-65. (Maness)) Further, CIGFUR notes that the environmental liability DEP is now tasked with managing is an environmental compliance cost that did not exist when the coal was burned, but arose only much more recently, and that applying a demand factor is consistent with the treatment of end-of-life nuclear fuel costs and nuclear decommissioning costs. (Id. at 289-90.)

In its post-hearing brief, NCSEA argues that costs associated with coal ash remediation are appropriately classified as energy-related costs.

The Commission has carefully considered the evidence presented by the witnesses. The evidence indicates that there have been a mixture of allocation approaches used for costs associated with fuel expense and other expenses over the years, with fuel and other energy-related costs following an energy allocation approach, while other costs, including certain spent fuel costs and costs associated with end-of-life plant costs, have been allocated consistent with the allocation of production plant, which the Commission notes has sometimes been based on peak demand and sometimes based on some type of average of energy and peak demand. The Commission can see credible arguments for the allocation of CCR clean-up costs on both sides – production plant or energy. However, CCR is a residual of the burning of coal in order to produce electricity. For every kWh of electricity that is produced by coal-fired generation, there are CCRs produced that must be properly handled and stored. Thus, the quantity of CCRs and the cost of storing them are energy driven. As a result, the Commission finds and concludes that the appropriate and reasonable course of action is to allocate the CCR costs by the energy allocation factor.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 63-65

The evidence supporting these findings of fact and conclusions is contained in the testimony of DEP witness Fountain and DEP's Late-Filed Exhibit 1.

Witness Fountain testified that DEP is engaged in litigation in Mecklenburg County involving 57 insurance policies purchase by DEP and DEC from 1971 to 1986. The lawsuit was filed on March 29, 2017. Witness Fountain testified that the lawsuit was filed after Duke Energy Corporation requested that the insurance companies provide coverage in connection with DEC's and DEP's liability for CCR costs. All of the insurance companies refused to pay Duke anything under the policies. Witness Fountain testified that DEP is seeking to recover its CAMA compliance costs and "seeking insurance proceeds that would offset those customer costs to the extent that they are provided in conjunction with these rate proceedings." (Tr. Vol. 7, p. 375.)

At the request of the Commission, on December 6, 2017, DEP filed its Late-Filed Exhibit 1. In summary, DEP's exhibit responds to the Commission's inquiries regarding the pending lawsuit, Duke Energy Carolinas, LLC, et al. v. AG Insurance SA/NV, et al., Case No. 17-CVS-5594, Superior Court (Business Court), Mecklenburg County, State of North Carolina (Insurance Case), in which DEP seeks insurance recovery for certain CCR related costs. DEP states that any net insurance recoveries from the Insurance Case will be used to reduce the CCR costs paid by DEP's customers. DEP further states that the Insurance Case seeks recovery under 19 excess-level third-party liability insurance policies issued to DEP's predecessor, Carolina Power & Light Company, between 1971 and 1986. DEP states that each policy will make a pay-out only after a "self-insured retention" – similar to a deductible – is satisfied, which deductibles range from $100,000 to $500,000 per policy. In addition, DEP states that the value and recoverability of the insurance proceeds is hotly disputed, and that each insurer in the Insurance Case takes the position that DEP is entitled to no recovery. Moreover, DEP states that "[i]t is possible that net recovery on behalf of the DEP ratepayers could amount to as much as $300 million dollars over time as future costs are incurred taking into account all of the DEP policies sued upon." DEP Late-Filed Exhibit 1, at p. 2.

Several parties questioned whether DEP has sufficient direct interest in the Insurance Case to motivate DEP to make a reasonable effort at recovering the maximum amount possible to off-set its customers' CCR costs. For example, in its post-hearing Brief Fayetteville PWC recommended that the Commission place three conditions on DEP's recovery of insurance proceeds: (1) DEP will be entitled to the immediate collection from the deferred account of an amount equal to the insurance proceeds that DEP secures for coal ash remediation from the Mecklenburg Case, provided that the offsetting insurance proceeds are credited to DEP's ratepayers; (2) if DEP fails to recover all or any of the insurance proceeds, DEP's CCR cost recovery should be reduced by the amount not recovered, unless DEP satisfies the Commission that it was not at fault in failing to get full insurance recovery; and (3) DEP would not be allowed to accrue a carrying charge on its deferred costs commensurate with any amount of insurance proceeds that it does not recover.

The AGO posits that ratepayers should not bail out DEP from its failure to pursue insurance coverage. Currently, DEP is seeking insurance coverage and has indicated that the total amount of recovery of policies sued upon "may total approximately" between $172 million to $200 million per occurrence. The Company further states that the net recovery on behalf of ratepayers could amount to as much as $300 million. The Company has agreed to use the insurance proceeds to offset the amounts it is otherwise seeking to recover; however, the AGO argues that DEP is disinterested in the outcome. The AGO contends currently there is no downside to DEP if it loses the insurance cases because DEP does not view itself as a stakeholder in the outcome. Further, the AGO contends that DEP might have not filed its claims in time and that the statute of limitations might have run. The AGO requests that if recovery is allowed that the Commission should earmark $300 million as being recovered in damages from the insurance case. The AGO further requests that the Commission should not allow a rate of return on the portion of the coal ash costs that may be recovered via the insurance case.

The Commission is not persuaded that it should adopt Fayetteville's PWC's first recommendation. It appears that the suggestion that DEP be allowed "immediate collection" from the deferred account would not require any Commission review of the deferred CCR costs for prudency or reasonableness. Thus, for example, if DEP settled the litigation for $200 million, it would immediately collect $200 million from the deferred account and be required to immediately credit ratepayers for $200 million. However, if $100 million of DEP's $200 million deferred CCR costs was not prudently or reasonably incurred, then $100 million of the insurance proceeds would go for CCR costs that should be disallowed.

The Commission agrees in principle with Fayetteville's PWC's second recommendation and the AGO's contentions. DEP is representing the interests of its ratepayers in the Insurance Case. Therefore, the Commission finds it appropriate to hold DEP to the same standard of care that DEP is required to exercise each day in providing electric service. That standard is one of reasonableness and prudence. If the parties to this docket, or the Commission on its own motion, raise meritorious issues about DEP's representation of the interests of ratepayers in the Insurance Case, DEP shall bear the burden of proving that it exercised reasonable and prudent efforts to obtain the maximum recovery in the Insurance Case.

With respect to Fayetteville's PWC's third recommendation as well as the AGO's request, the Commission again agrees in principle. However, a blanket denial of carrying costs based solely on DEP's failure to recover every dollar of insurance coverage would be unfair. Rather, the Commission concludes that if DEP exercises reasonable care in representing its ratepayers' interests in the Insurance Case, then DEP should be entitled to receive its full authorized carrying charges on the deferred account. As stated above, if there is a meritorious issue raised about DEP's representation of the interests of its ratepayers in the Insurance Case, DEP shall bear the burden of proving that it took reasonable and prudent steps to obtain the maximum recovery. If DEP fails to meet this burden, the Commission can deny DEP carrying costs on that amount of insurance proceeds that were not recovered as a result of DEP's lack of reasonable and prudent efforts.

Finally, the Commission concludes that DEP should be required to place all insurance proceeds received or recovered by DEP in the Insurance Case in a regulatory liability account and hold such proceeds until the Commission enters an order directing DEP as to the appropriate disbursement of the proceeds. In addition, the regulatory liability account shall accrue a carrying charge at the overall rate of return authorized for DEP in this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 66

The evidence supporting this finding of fact and conclusion is contained in the testimony of DEP witnesses Bateman and Simpson, and Public Staff witness Maness.

DEP witness Bateman testified that DEP is requesting authority to establish a regulatory asset in which to record and defer the cost of existing AMR meters that are replaced by AMI meters. She stated that the Company's Depreciation Study recovers the net value of the meters being replaced over three years, which is the expected AMI deployment period.

DEP witness Simpson testified that pending a management review and approval by the Duke Energy Board of Directors later this year, DEP plans to begin a full deployment of AMI meters in 2018. He also noted the testimony of witness Bateman regarding DEP's request to establish a regulatory asset in which to record and defer the cost of existing AMR meters that are replaced by AMI meters.

Public Staff witness Maness testified that the Public Staff does not oppose the establishment of a regulatory asset to track the remaining depreciation of replaced meters. Further, he recommended that the replaced meters be depreciated using their estimated remaining useful life of 18.3 years, rather than over three years, as recommended by DEP.

The Commission finds and concludes that DEP should be allowed to establish a regulatory asset account and defer to that account the cost of existing AMR meters replaced by AMI meters. However, the approval granted herein is without prejudice to the right of any person to contest the recovery of the amount of the regulatory asset in future rates, and is without prejudice to the Commission's authority to deny or reduce such recovery if the Commission concludes that DEP has not complied with the Commission's rules or other requirements.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 67

The evidence supporting this finding of fact and these conclusions is contained in the testimony of DEP witness Bateman.

With regard to DEP's CCR costs from 2018 forward, DEP witness Bateman testified that DEP is requesting to establish a regulatory asset/liability account and defer to this account the portion in annual rates that is more than DEP’s actual costs, or the amount in annual rates that is less than DEP's actual costs. In essence, the asset/liability account would be a tool used to true-up the difference in DEP’s next general rate case.

The Commission agrees with DEP’s recommended approach, not only for CCR costs, but also for all cost deferral accounts. A deferred cost is not the same as the other cost of service expenses recovered in the Company’s non-fuel base rates. A deferred cost is an exception to the general principle that the Company's current cost of service expenses should be recovered as part of the Company's current revenues. When the Commission approves a typical cost of service, such as salaries and depreciation expense, there is a reasonable expectation that the expense will continue at essentially the same level until the Company’s next general rate case, at which time it will be reset. On the other hand, when the Commission approves a deferred cost the Commission identifies a specific amount that has already been incurred by the Company, or, in the case of CCR costs, is estimated to be incurred by the Company. In addition, the Commission sets the recovery of the amount over a specific period of time. Further, the Company is directed to record the recovery of the specific amount in a regulatory asset account, rather than a general revenue account. If DEP continues to recover that deferred cost for a longer period of time than the amortization period approved by the Commission that does not mean that DEP is then entitled to convert those deferred costs into general revenue and record them in its general revenue accounts. Rather, the Company should continue to record all amounts recovered as deferred costs in the specific regulatory asset account established for those deferred costs until the Company’s next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 68

In the post-hearing briefs of CUCA and other intervenors, the parties contended that the Commission should adjust DEP’s rates to incorporate the effect of the federal income tax decrease included in the Federal Tax Cuts and Jobs Act of 2017 (FTCJA). CUCA estimates that the annual monetary value in the tax reduction is approximately $116.9 million as stated in its comments in Docket No. M-100, Sub 148.

The AGO, in its post-hearing Brief, notes that the Commission has opened a rulemaking proceeding to consider the rate adjustments that public utilities should make to reflect the impact of the tax cut effectuated by the Federal Tax Cuts and Jobs Act (FTCJA). The AGO states that it will participate in the rulemaking and asks the Commission to take appropriate action in this case to order that rates established in this docket will be billed and collected on a provisional basis and that an appropriate deferral will occur, as directed in the FTCJA Order initiating the proceeding, pending final disposition of the rulemaking in order to reflect the benefit of the tax cut in rates.

In its post-hearing Brief, EDF contends that the Commission should require DEP to reflect the federal income tax reduction effectuated by the FTCJA in its new rates. In support of its position, EDF states that a similar event occurred when Congress passed the Tax Reform Act of 1986, which cut the federal income tax rate from 46% to 34%. The Commission opened Docket No. M-100, Sub 113 to investigate how to reflect the federal income tax reduction in rates. In the appeals that followed, the Supreme Court of North Carolina upheld the Commission's authority to reduce utilities' rates to reflect the federal income tax change, either through a general rate case or through a rulemaking. State ex rel. Utilities Com. v. Nantahala Power & Light Co., 326 N.C. 190, 388 S.E.2d 118 (1990). EDF acknowledges that on January 3, 2018, the Commission opened Docket No. M-100, Sub 148 to address the FTCJA issues.

In its post-hearing Brief, Kroger notes that on December 22, 2017, the FTCJA was signed into law, lowering the Federal corporate income tax rate from 35% to 21%. Kroger states that the Commission noted in its Order initiating proceedings in Docket No. M-100, Sub 148, that the reduction in the corporate income tax rate will have an immediate and favorable impact on the cost of providing services to utility customers, including the customers of DEP. Kroger contends that income taxes are a cost of service for ratemaking, and that when tax expense goes down so too should rates. Kroger urges the Commission to recognize the impact of the new tax rate in this proceeding by lowering customer rates commensurate with DEP's reduced tax expense.

On January 3, 2018, the Commission issued an Order in Docket No. M-100, Sub 148 initiating an inquiry into the effects of the FTCJA. The Commission's Order included notice to affected utilities that effective January 1, 2018, the Federal corporate income tax expense component of all existing rates and charges will be billed and collected on a provisional rate basis. Therefore, the Commission will address the effects of the FTCJA in Docket No. M-100, Sub 148.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 69-71

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

The Company presented Settlement Exhibit 1, Schedule 1 and Updated Bateman Exhibit 1 – Partial Settlement reflecting DEP's revised requested increase incorporating the provisions of the Stipulation, the Company's position on the unresolved issues and the impact of the EDIT decrement rider. Per those exhibits, the resulting proposed revenue requirement of the Company is $305,955,000. Second Revised Settlement Exhibit 1, Schedule 1 shows the Public Staff's revised recommended increase incorporating the provisions of the Stipulation, the impact of the EDIT decrement rider and its adjustments (Coal Ash, Storm Costs) reflecting the Public Staff's position on the

Unresolved Issues. The resulting proposed revenue requirement by the Public Staff is $99,726,000.

As discussed in the body of this Order, the Commission approves the Stipulation in its entirety and makes its individual rulings on the unresolved issues as discussed. Due to the intricate and complex nature of some of the issues, the Commission requests that DEP recalculate the required annual revenue requirement as consistent with all of the Commission's findings and rulings herein within 10 days of the issuance of this Order. The Commission further orders that DEP work with the Public Staff to verify the accuracy of the recalculations. Once the Commission receives this filing, the Commission will work promptly to verify the calculations and will issue an Order with final revenue requirement numbers.

In addition, the Commission requests that DEP and the Public Staff provide the Commission with the demand and energy allocation factors that they, respectively, deem appropriate for allocating the CAMA costs to the North Carolina retail jurisdiction.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 72

The evidence supporting this finding of fact and conclusion is contained in the Application, the testimony and exhibits of all the witnesses, the Stipulation, and the entire record in this proceeding.

Pursuant to G.S. 62-133(a), the Commission is required to set rates that are "fair both to the public utilities and to the consumer." In order to strike this balance between the utility and its customers, the Commission must consider, among other factors, (1) the utility's reasonable and prudent cost of property used and useful in providing adequate, safe and reliable service to ratepayers, and (2) a rate of return on the utility's rate base that is both fair to ratepayers and provides an opportunity for the utility through sound management to attract sufficient capital to maintain its financial strength. See G.S. 62-133(b). DEP's continued operation as a safe, adequate, and reliable source of electric service for its customers is vitally important to DEP's individual customers, as well as to the communities and businesses served by DEP. DEP presented credible and substantial evidence of its need for increased capital investment to, among other things, maintain and increase the reliability of its system and comply with environmental requirements.

In its Application and testimony, DEP stated that since 2013 it has been adding new gas-fueled generation, along with adding new utility-scale solar facilities, to replace older, less-efficient coal-fired generation. In addition, DEP noted that it began construction on its Asheville Combined Cycle Plant, and has almost completed construction of its new Sutton Blackstart Combustion Turbine. According to DEP, approximately $253 million of its initially requested $477.5 million revenue increase was intended to recover the costs associated with these plant additions and upgrades. In addition, DEP stated that it has started complying with recently adopted federal and state rules regarding the handling of CCRs and closure of CCR basins, and that $66 million of the requested $477.5 million increase was intended to recover ash basin closure compliance costs incurred since January 1, 2015. Further, DEP stated that it was requesting to recover $129 million toward ongoing ash basin closure compliance costs, with any difference from the requested amount and actual costs to be deferred until a future general rate case. DEP stated that the remaining $29 million of the requested rate increase was intended to recover costs related to tax rate changes, major storm restoration costs, nuclear development costs, and an updated Customer Information System.

These are representative examples of the capital investments that have been made and are planned to be made by DEP in order to continue providing safe, reliable and efficient electric service to its customers.

In addition, the rate increase approved herein is mitigated to some extent by the Partial Settlement Agreement entered into between DEP and the NC Justice Center, wherein DEP agrees to contribute $2.5 million to the Helping Home Fund for low-income energy assistance.

Based on all of the evidence, the Commission finds and concludes that the revenue requirement, rate design and the rates that will result from this Order strike the appropriate balance between the interests of DEP's customers in receiving safe, reliable and efficient electric service at the lowest possible rates, and the interests of DEP in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the Commission concludes that the revenue requirement and the rates that will result from that revenue requirement established as a result of this Order are just and reasonable under the requirements of G.S. 62-30, et seq.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation filed by DEP and the Public Staff is hereby approved in its entirety.

2. That DEP is entitled to recover the actual coal ash basin closure costs DEP has incurred (netted against the amount already included in the Company's rates following its last rate case) during the period from January 1, 2015 through August 31, 2017, less a disallowance of $9.5 million, for a total amount to $232,390,000, to be adjusted based on the allocation factors to be provided by DEP and the Public Staff pursuant to Ordering Paragraph No. 5. These costs shall be amortized over a five-year period, with a return on the unamortized balance and then reducing the resulting annual revenue requirement by $6 million for each of the five years.

3. That DEP is authorized to record its September 1, 2017 and future CCR costs in a deferral account until its next general rate case. This deferral account will accrue a return at the overall rate of return approved in this Order.

4. That the appropriate revenue requirement for the first four years shall be reduced by the EDIT Rider decrement of $42.577 million.

5. That DEP shall recalculate and file the annual revenue requirement with the Commission within 10 days of the issuance of this Order, consistent with the findings and conclusions of this Order and the Stipulation. The Company shall work with the Public Staff to verify the accuracy of the filing. DEP shall file schedules (North Carolina Retail Operations – Statement of Rate Base and Rate of Return, Statement of Operating Income, and Statement of Capitalization and Related Costs) summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determinations in this proceeding. In addition, DEP and the Public Staff shall provide the Commission with the demand and energy allocation factors that they, respectively, deem appropriate for allocating the CAMA costs to the North Carolina retail jurisdiction.

6. That DEP is hereby authorized to adjust its rates and charges in accordance with the Stipulation and findings in this Order effective for service rendered on and after the following day after the Commission issues an Order accepting the calculations required by Ordering Paragraph No. 5.

7. That the Commission shall issue an Order approving the final revenue requirement numbers once received from DEP and verified by the Public Staff as soon as practicable.

8. That the three settlement agreements entered into by DEP with Commercial Group, Kroger, and NC Justice Center are in the public interest and should be approved in their entirety.

9. That within 10 days of the resolution by settlement, dismissal, judgment or otherwise of the litigation entitled Duke Energy Carolinas, LLC, et al. v. AG Insurance SA/NV, et al., Case No. 17 CVS 5594, Superior Court (Business Court), Mecklenburg County, North Carolina (Insurance Case), DEP shall file a report with the Commission explaining the result and stating the amount of insurance proceeds to be received or recovered by DEP. This reporting requirement shall apply even if the case is appealed to a higher court.

10. That DEP shall place all insurance proceeds received or recovered by DEP in the Insurance Case in a regulatory liability account and hold such proceeds until the Commission enters an order directing DEP regarding the appropriate disbursement of the proceeds. The regulatory liability account shall accrue a carrying charge at the overall rate of return authorized for DEP in this Order.

11. That the approved base fuel and fuel-related cost factors are as follows (amounts are cents per kWh, excluding regulatory fee): 1.993 for residential customers; 2.088 for SGS customers; 2.431 for MGS customers; 2.253 for LGS customers; and 0.596 for Lighting customers.

12. That the Company shall implement an increment rider, effective on the same date as its new base rates, and expiring at the earlier of (a) January 30, 2020, or

(b) the last day of the month in which the Company's actual coal inventory levels return to a 35-day supply for three consecutive months of total coal inventory of 37 days or less, to allow the Company to recover the additional costs of carrying coal inventory in excess of a 35-day supply (priced at $76.11 per ton). The interest on any under- or over-collection shall be set at the Company's net-of-tax overall rate of return. The Company shall adjust the rider annually, concurrently with its DSM/EE, REPS, JAAR and Fuel Adjustment riders.

13. That on or before December 31, 2018, the Company and the Public Staff shall complete an analysis showing the appropriate coal inventory level given market and generation changes since the Company's rate case in Docket No. E-2, Sub 1023.

14. That the Company shall conduct a workshop on its Power/Forward grid investments in the second quarter of 2018.

15. That the aspects of rate design agreed upon in the Stipulation are approved and shall be implemented.

16. That DEP shall not be allowed to defer the costs of the June and July 2016 thunderstorms amounting to $1.720 million in O&M expenses.

17. That DEP shall be, and is hereby, allowed to defer incremental O&M costs of 2016 storms in the total amount of $51.032 million.

18. That DEP is authorized to record the incremental storm cost amortization expense over a five-year period beginning with the month of October 2016.

19. That DEP's request for deferral of the depreciation expense and carrying costs related to the 2016 storms at its weighted average cost of capital on the capital investments, and the carrying costs at its weighted average cost of capital on the deferred costs, shall be, and is hereby, denied.

20. That DEP shall within 30 days of the date of this Order make a $2.5 million contribution from shareholder funds to the Helping Home Fund to be used for low-income energy assistance in DEP's North Carolina service territory.

21. That DEP is allowed to collect in rates a North Carolina retail normalized annual level of storm costs in the amount of $11.018 million.

22. That the Commission's approval in this Order of deferral accounting and other accounting procedures is without prejudice to the right of any party to take issue with the amount of or the accounting treatment accorded these costs in any future regulatory proceeding.

23. That the Company's proposal for a JRR, as modified by this Order, and the JRRR are hereby approved for a one-year pilot with an option to renew it for a second year if the Company provides evidence that the JRR is achieving its intended purpose.

24. That the JRR and JRRR revenues shall be reported to the Commission annually, if the JRR is in effect more than one year, and the JRRR shall be reviewed and will be subject to adjustment annually coincident with DEP's December fuel adjustment to match anticipated recovery revenues and true-up any past over-or under-recovery.

25. That due to the uncertain date of implementation, compliance tariffs shall be filed prior to implementation of the JRRR and customers shall be notified by bill insert or message upon implementation.

26. That within 30 days of this Order, but no later than 10 business days prior to the effective date of the new rates, DEP shall file for Commission approval five copies of all rate schedules designed to comply with this Order, accompanied by calculations showing the revenues that will be produced by the rates for each schedule. This filing shall include a schedule comparing the revenue that was produced by the filed schedules during the test period with the revenue that will be produced under the proposed settlement schedules, and a schedule illustrating the rates of return by class based on the revenues produced by the rates for each schedule.

27. That DEP shall submit a proposed customer notice to the Commission for review and approval, and upon approval of the notice by the Commission, shall give appropriate notice of the approved rate increase by mailing the notice to each of its North Carolina retail customers during the billing cycle following the effective date of the new rates.

28. That the Company shall file annual cost of service studies based on both the SCP and SWPA methodologies.

29. That DEP shall be, and is hereby, authorized to establish a regulatory asset to defer and amortize the costs of its Customer Connect Program (CCP). The regulatory asset account shall accrue AFUDC until the DEP Core Meter-to-Cash release (Releases 5-8) of the CCP project goes into service, or January 1, 2022, whichever is sooner. At that point, the costs will be amortized over 15 years.

30. That DEP shall file reports regarding the development, spending and accomplishments of the CCP each year on December 31 for the next five years, or until the CCP is fully implemented, whichever occurs later. Further, DEP and the Public Staff shall develop a format for the annual CCP report and file the format with the Commission within 90 days of the date of this Order.

31. That DEP shall be, and is hereby, authorized to defer to a regulatory asset account the cost of existing AMR meters replaced by AMI meters. However, the approval granted herein is without prejudice to the right of any person to contest the recovery of the amount of the regulatory asset in future rates, and is without prejudice to the Commission's authority to deny or reduce such recovery if the Commission concludes that DEP has not complied with the Commission's rules or other requirements.

32. That if DEP receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company shall continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case.

This 23rd day of February, 2018.

NORTH CAROLINA UTILITIES COMMISSION

Janice H. Fulmore, Deputy Clerk

Commissioner ToNola D. Brown-Bland dissents in part.

Commissioner Daniel G. Clodfelter concurs in part, and dissents in part.

Commissioner Charlotte A. Mitchell did not participate in this decision.

DOCKET NO. E-2, SUB 1131
DOCKET NO. E-2, SUB 1142
DOCKET NO. E-2, SUB 1103
DOCKET NO. E-2, SUB 1153

Commissioner ToNola D. Brown-Bland, dissenting in part:

I dissent from the majority opinion with respect to the Findings of Fact 35, 54 and 55 and discussion leading to the determination that the Company is entitled to full recovery of all coal ash expenses subject to a one-time mismanagement penalty. I acknowledge that the penalty imposed represents an attempt to hold the Company accountable for its admitted mismanagement and oversight of its coal ash handling and disposal operations. However, this approach, without further analysis, does not reasonably assure that the rates fixed for the Company's service are "fair to both the public utilit[y] and to the consumer," and that the rate set by the Commission and to be received by the Company is just and reasonable. G.S. 62-133 and 131. It is not fair to burden the consumers with rates that include costs attributable to the Company's imprudence nor is it fair to the Company to disallow recovery of reasonable costs necessary to the provision of adequate, efficient and reasonable service.

Fairness in rate fixing requires the Commission to undertake reasonable effort to examine the incurred costs sought to be recovered and distinguish among such costs to reasonably assure consumers are not burdened with costs that are unfair and the utility Company is not denied recovery of its reasonable costs. In this general rate case at hand, imposition of the penalty alone without analysis of costs to determine why they were incurred does not meet the Commission's duty to fairly balance the interests of the consumer and the Company and to reasonably assure that costs are fairly assigned between the two. A one-time penalty cannot substitute for the Commission's duty to make rates that are fair to both the public utility and the consumer on a case by case basis considering the evidence of record in each case.

While it concluded the Company should face a consequence for its mismanagement, the majority failed to acknowledge that the Company's admission in a court of law to mismanagement of its coal combustion residual activities through inadequate oversight that led to unlawful water pollution is conclusive evidence of its imprudence in handling, storage and management of coal ash. Pleading guilty to unlawful criminal activity, *i.e.*, four counts of criminal negligence resulting in coal ash pollutant discharges to surface waters, established negligence per se and therefore it is appropriate to conclude in the case at hand, where the prudence of the Company's actions is at issue, that the same plea established imprudence per se.[1] Where the Company has pled guilty to criminal negligence a finding that its actions concerning those criminal negligent actions were prudent is contrary to law.

Moreover, the Company's imprudence is also established based on other evidence of record in this case. Even if for the sake of argument, the Company's position is accepted that at all times relevant its coal ash handling practices and actions met the requirements of applicable statutory law and regulations, the evidence, as discussed below, shows that the Company failed in or breached its *legal* duty to exercise the ordinary duty of care to protect life, property and the environment from harm and unreasonable risks in the performance of its lawful activities and business obligation to properly handle, store and manage coal ash laden with heavy metals and other contaminants. This ordinary duty of care (and it could be argued the Company has a higher duty stemming from the nature of electric generation and related coal combustion activities) exists at all times and, unless otherwise stated expressly by statute, is not excused by mere compliance with statutes and regulations. Despite its recognition that its guilty plea in federal court was acknowledgement of failure to live up to its own standards, the Company seems to toss aside its ever present duty of care and argue its only duty is compliance with statutes and regulation. It seems to further argue that any action or costs beyond bare compliance would be wrong or considered gold plating by this Commission.[2] Yet the Company's own testimony of record shows that it knows better. Company witness Wells testified that in 2006 DEP began groundwater monitoring activities related to its ash facilities without being required to do so by any law or regulation. It is reasonable to infer the Company knew or intuitively recognized in 2006 that it had a duty of care to monitor the groundwater as part of basic safety and environmental protection obligations that could not be delayed due to cost recovery concerns. Actors such as the Company cannot avoid the basic duty of ordinary care to take steps to protect others from unreasonable risks or harm based on concerns that cost recovery from this Commission or any other agency may be denied. Therefore, the applicable standard of care for the Company is not only compliance with statutes and regulations but also compliance with the legal duty of ordinary care as discussed above. Where, as here and as will be discussed below, the evidence of record establishes both that the Company breached this duty and that certain incurred costs were caused as a result of such breach, the majority's finding that incurring those identified costs was reasonable and prudent is contrary to law.

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[1] Violations of statutes which 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).

[2] The gold plating argument is a convenient one and may have been more convincing if the Company had presented a plan to improve its coal ash management safety and compliance practices to the Commission and had shared what it learned from the Sutton report as will be discussed herein.

The evidence of record generally shows that around the 1920s when the Company began providing electric service in our state, it did so by generating electricity through the combustion of coal. The generation process created the byproduct of coal ash. At the time, neither the use of fossil fuel in power generation nor the ash byproduct were known to be particularly harmful to human well-being or the environment. Nevertheless, the ash resulting from the generation process was substantial and the Company as part of its provision of service undertook the obligation to properly manage it. It is presumed that during this time period, the rates approved by the Commission and paid by ratepayers were adequate to compensate the Company for its costs for its proper management of the coal ash byproduct. The part of the ash that did not fly into the atmosphere through smokestacks was collected by the Company from the bottom of boilers and placed in on-site storage areas. Before there were ash basins or landfills, the bottom ash would have been placed in a lay of the land area. This could have created a pile on-site or just filled in a low area.

Neither the creation nor management of the ash in this manner was negligent based on the then current knowledge and foreseeability of the risks at that time. In choosing fossil fuel generation, the Company complied with the state's policy of providing service at the least cost and the consumers benefitted from this choice at least in the form of low electric rates for decades down to the present. Storing the dry ash on-site was not negligent as the scientific and healthcare communities had not determined that such disposal could pose a substantial risk of harm to people or the environment and the environmental risks of harm or injury from coal ash management practices were not then foreseeable by the Company. This method of storage also complied with the state's least cost policy from which consumers benefitted in the form of low electric rates.

In the 1950s, the Company, in alignment with the power industry at the time, created unlined basins and ponds to serve as repositories for coal ash sluiced out of boilers using water. The Company's repositories were created on-site with the generation plants from the mid-1950s through 1985. When this practice began in the 1950s, unlined basins were the primary technology for treating and handling coal ash throughout the country. There were no governmental regulations requiring that the ash repositories be lined for safety or health reasons and the scientific and healthcare communities still had not formed a certain opinion as to the risk of harm posed by unlined ash basins and ponds. The evidence before the Commission does not establish that the Company knew or reasonably foresaw that its coal ash handling practices were problematic or harmful to human life or the environment. Neither our state nor our nation was particularly environmentally aware or concerned with the harmful implications of coal ash management practices before around the time the United States Environmental Protection Agency (EPA) was established in 1970. Thus, it remained true that neither the ash created up through this time nor the Company's early coal ash management activities, including treatment of wet ash in unlined repositories, was imprudent. Fossil fuel generation and wet coal ash treatment in unlined basins and ponds was also compliant with the state policy that electric service be provided for the least cost and consumers continued to benefit in the form of low electric rates. Again, it is presumed that during this time period, the rates paid by ratepayers were adequate to compensate the Company for its costs for its proper handling and disposal of the coal ash.

By 1972, the EPA had begun to regulate unlined coal ash basins under the Clean Water Act and set groundwater standards for industry and water quality standards for contaminants in surface waters. The federal regulation of ash basins was clear indication to power generators like the Company that coal ash was being examined as posing a threat to ground and surface water. By 1979, the State of North Carolina's environmental regulator (today known as DEQ) implemented what is known as the 2L water regulations. Since 1983, these rules required persons including the Company to take actions both to prevent and correct groundwater contamination. By 1988, as reported publicly by the EPA in its report to Congress on wastes from power plant combustion of coal, 40% of generating units built after 1975 used lined ash disposal facilities. The EPA began regulating coal combustion waste under the Resource Conservation and Recovery Act in 2000. In 2008, a huge spill of over 5 million cubic yards of coal ash occurred at the Tennessee Valley Authority Kingston Fossil Plant, which resulted in ash being released into the Emory River. That spill caused both the industry and the EPA to focus more on, among other related issues, understanding the threat posed by unlined coal ash basins to surface and ground water. By 2010, the EPA had developed and issued proposed rules regarding Coal Combustion Residuals (CCR Rules) and had begun the process of receiving comments from interested parties, including power producers.

Thus, the evidence shows the Company had known for about 30 years prior to enactment of the North Carolina Coal Ash Management Act (CAMA) that the state's 2L water regulations required it to prevent and to correct exactly the kind of pollution which the Company admitted through its guilty plea it negligently allowed to occur from at least 2010 through 2014. The TVA incident combined with the regulatory response and the participation of the industry, including the Company, in the EPA rulemaking process informed or should have informed the Company, by 2010 and well before the 2014 enactment of CAMA, of the gravity of the situation surrounding the proper management of coal ash, which was continuing to mount as coal continued to be used in the generation process to meet customer demand for electric power. With knowledge of the foregoing regulatory efforts and requirements as well as the spill incident, the Company certainly had a clear obligation, by 2010 if not sooner, in the exercise of due care to monitor its repositories and take action upon any evidence that the repositories were not containing the coal ash in the intended and required manner. That is to say, that between the TVA spill in 2008 and 2010, by keeping abreast of EPA activities related to the spill including developing the CCR Rules, and through its knowledge of the state requirements making it unlawful to exceed established groundwater contamination levels, the Company knew the concerns and risks associated with coal ash contamination. It is reasonable to infer from the evidence that the Company was aware that it ran the risk of its unlined ash containment repositories failing to contain and that such failure would likely result in unlawful water contamination. It is against the weight of the evidence to infer that the Company was unaware of these risks.

In fact, the evidence further establishes that well prior to the notable and historical TVA spill and the 2014 release of ash into the Dan River from Duke Energy Carolinas' Dan River Steam Station, DEP had actual knowledge that its own ash basins at the Sutton and Asheville plants were not serving their essential purpose of effectively treating and containing ash—at least not at the level that was reasonably expected or required by the Company's duty to exercise due care in coal ash management activities. The National Pollution Discharge Elimination System (NPDES) permitting system, adopted in 1972 with permitting authority granted to North Carolina in 1974, implements standards under the federal Clean Water Act for preventing pollutants from being discharged into surface waters. Similarly, North Carolina's 2L standards were adopted in 1979 to set limits on harmful groundwater pollutants and to require corrective action when pollution occurs. First the evidence is that there were a number of NPDES permit violations and unlawful groundwater exceedances at DEP coal-fired plant sites, including the Sutton and Asheville plants, going back at least 10 years, *i.e,* as far back 2007. The Company knew of the 2007 violations and exceedances when they were noticed by DEQ in 2007. Indeed, DEP witness Wells testified that since 2010 DEP has been attempting to persuade DEQ to issue NPDES permits authorizing DEP's seeps, but DEQ has thus far chosen not to permit them.

Aside from whatever the status of the evolution of ash regulation may have been, upon learning that seeps and exceedances were attributable to its unlined ash ponds and basins, the Company's duty of ordinary care required it to take timely steps to manage its ash *i.e.*, by properly maintaining its water treatment equipment or by removing ash from unlined ponds and placing it in properly lined repositories. Not taking such steps to arrest the seeps and exceedances for more than seven years while waiting for DEQ to act on the Company's request to approve and permit the seeps was not reasonable. It was a breach of the Company's duty of care and imprudent.

The Company's knowledge of the inadequacy of its coal ash management practices is further documented by its own L.V. Sutton Steam Electric Plant long term ash strategy study phase report (Sutton report) produced in November 2004 by the engineers of the Company's fossil generation department.[3] The report provides substantial and convincing evidence that the Company knew its unlined ash ponds were not in compliance with applicable coal ash regulations and posed a risk of failing to contain the ash contaminants. The report put forth for consideration a number of alternatives for handling ash at the Sutton plant because of then present and foreseeable issues with two Sutton ash ponds. The existing 1984 ash pond was predicted to be out of capacity for any future ash storage by June 2006 based on the ash production levels occurring at the time.

[3] Attorney General's Office —Wells Cross Exhibit 3.

The 1983 pond was unlined and viewed by the Company's engineers not to meet current ash management compliance requirements. In addition, the study examined and addressed another unlined disposal site on the Sutton property that was used when the plant first went in service, but that had not been studied to determine the extent of any issues it posed and "ha[d] not been high on the EPA's radar."[4]

A cross-disciplinary Company team, that included, among others, representatives from Fossil Generation Department East Region Engineering, Technical Services Department Ash Management, Total Suspended Solids Environmental Section, The Treasury Department and <u>two</u> contract engineering firms, recommended that the Company take steps toward a solution that would accommodate "all of the plant's previous ash production from both the 1983 and 1984 ash ponds and the pre-ash pond disposal site" that would "allow for construction to begin no later than January 2006 to support the 1984 ash pond end of life" forecasted to be June 2006. The solution that the Company team of engineering and environmental experts recommended was the development and construction of an Industrial Park. The study team noted "this option would eliminate the need for the two associated projects of relining [with a compliant liner] the 1983 ash pond and the remediation of the pre-ash pond disposal site." It was further noted that the fastest possible construction for such an Industrial Park would be 3 years, *including "the moving of the ash from the existing sites."* Thus, in addition, the Sutton report identified a contingency plan being implemented for a vertical dike extension to allow the plant to continue to generate electricity for the next 5 to 7 years.

Statements contained in the Sutton report demonstrate that as of 2004, contrary to claims that the Company was always in full compliance with existing regulation, the Company was aware that its unlined ponds were not in compliance with the current regulatory standards and posed contamination risks. In discussion of the 1983 unlined pond, the report contains the following:

> The first issue is that the 1983 ash pond was constructed during a period when it was not required to provide a non-permeable liner, and was constructed with the native sandy soils. This pond has been functionally full since 1983, but is still permitted, and is occasionally used when there are issues requiring the 1984 pond to be temporarily dry. The current environmental atmosphere is that these ponds will eventually have to [sic] emptied and *placed in a lined containment to eliminate the leaching of the*

[4] Although this site contained as much or more ash as the 1983 pond, which was functionally full, and had once been designated a Superfund site, it appears from the report that the Company had not cleaned it up or taken any action to remediate apparently because the environmental regulators had not pushed it to do so. Again, regulator inaction or leniency does not relieve an actor like the Company from its ordinary duty of care to prevent or stop a harmful situation it created in the performance of its business activities.

ash products into the ground water system. This is an issue that is not currently being pressed, but it is anticipated that with the tighter environmental conditions it will soon become an emergent issue. This issue is aggravated by the fact that a test monitoring well located 300' from edge of the 1983 ash pond has shown high levels of arsenic during the past two quarterly tests. *This may or may not be related to the unlined ash pond.* A recent study by an independent firm indicated this concern may be less than originally thought. *It could be mitigated* by adding monitoring wells to the NPDES permit, *but could still pose an issue in the future*. [All italics added.]

Sutton Report, p. 2. The language in the quoted passage reveals that the company engineers knew at the time of the report that the days when unlined ash ponds were allowed were in the past; that unlined ponds allowed leaching of ash products into ground water and that the purpose of a non-permeable liner was to "eliminate" such leaching; that the 1983 pond could possibly be leaching arsenic; and that even if the arsenic situation were mitigated, it could still pose an issue in the future, making mitigation an insufficient remedy. Thus, the Company and its engineers knew in 2004 that its unlined ash ponds posed a risk of coal ash contaminants leaching into ground water and that one way to stop and effectively remedy that risk or any actual leaching was to place the contents of unlined ponds into lined containment facilities.

The fact that the engineers were not certain at the time of the internal publication of their report whether the 1983 pond was leaching arsenic does not negate their actual knowledge that the pond might have been leaching and could pose a future issue regardless. While the report shows that Company engineers attempted to redress the capacity problems with temporary solutions based on maintaining existing discharge permits and were willing to consider adding additional monitoring wells to perhaps mitigate leaching issues, taken as a whole it nonetheless also indicates that these solutions were viewed only as short term fixes. The report demonstrates that the engineers recognized and recommended that the situation called for a long-term permanent solution to meet the already then current requirement to contain leachate and prevent and remediate water contamination. Having an active discharge permit for a non-compliant containment does not equate with compliance with ash pond or coal combustion residuals regulations.[5]

[5] In the Sutton report, the Company engineers were addressing two distinct problems: 1) maintaining pond discharge permits in order to keep the Sutton plant operating and 2) developing and making ash containment facilities that would comply with ash management regulations. An active discharge permit for a non-compliant ash pond was a measure the engineers recognized as affording the Company time to remedy non-compliance with a permanent solution like a new lined pond or an industrial park that would accommodate all of the Sutton ash as ground fill.

Additional statements from the 2004 report also show that the Company knew its unlined containment ponds were non-compliant with the then current regulations. As part of the discussion of the alternative of doing nothing to address the containment issues at Sutton, the report states, "It is assumed that the North Carolina Division of Water Quality (NCDWQ) [as part of its 'increased emphasis on ash ponds and their [e]ffects on the surrounding area and groundwater'] will require the 1983 ash pond to be emptied and lined to comply with *current* ash pond regulations." (Emphasis added.) Translation: At the time the report was written in 2004, the 1983 ash pond did not comply with the current ash pond regulations.

In discussion of other various new pond alternatives, the report states, "The new ash pond would be constructed with the current liner requirements including an impermeable liner with leak detection and monitoring system." This is further evidence the Company knew that to make its unlined repositories compliant with the regulations of 2004, impermeable liners would need to be installed to assure adequate containment of ash waste. Regarding new ponds or alternatives that would allow the 1983 and 1984 ponds to extend capacity for a few years and/or to combine capacity extension with beneficial use projects, the report points out that such solutions would not alleviate the need to line the 1983 ash pond or to have to remediate the pre-ash pond disposal site by 2019. The same was noted in the report with respect to an alternative that called for ash from the 1984 pond to be shipped to other non-plant site locations. In contrast, the report noted three other alternatives, including the industrial park alternative recommended by the engineers, would accommodate all the ash from the two ponds and the pre-ash pond disposal site and eliminate the need to line the 1983 pond and to remediate the pre-ash pond disposal site. The report leaves no doubt that Company engineers knew and advised the Company in 2004 that the old unlined pond was non-compliant, that in any scenario where the pond remained in use, the Company could not escape the requirement to line the pond with a non-permeable liner, and that the Company would in a short time be faced with stricter enforcement of compliance standards by the environmental regulators.

In sum, the 2004 Sutton report is evidence that the Company's own in-house and outside contract engineers put the Company on notice that its unlined (not lined with a non-permeable liner) ash ponds were not compliant with the environmental regulations of the day; that the unlined ponds were subject to leaching of their contents and that ash from at least one unlined Company pond might already be leaching into the groundwater; and that the Company had available to it a number of specific alternative actions that represented reasonable optional pathways to coal ash management compliance. Having this knowledge in 2004 but failing to take timely and appropriate action to bring its unlined ponds into compliance to stop and/or prevent leaching of contaminants into groundwater was at a minimum, whether held accountable by federal and state regulators or not, a breach of the Company's duty to exercise due care in its ash management activities. This failure was both negligent and imprudent.

Because as discussed above, the greater weight of the evidence supports a finding that the Company was negligent and imprudent in its coal ash management by failing to act in a timely and appropriate manner based on information contained in the Sutton report, as well as its NPDES permit and 2L violations, the Commission, in setting just and reasonable rates in the public interest, must examine the coal ash management costs that the Company seeks to recover in the case at hand to determine whether the costs are a result of the Company's imprudence. If the evidence supports a finding that specific costs were incurred by the Company due to the Company's own imprudence, then those costs would have been imprudently incurred. It would be unfair and not in the public interest for the Commission to set rates that are based upon allowing the Company to recover costs attributable to the Company's imprudence. Such rates would not be just and reasonable. On the other hand, if the evidence is insufficient to establish that particular coal ash management costs resulted from the Company's imprudence and those costs were otherwise prudently incurred to comply with current legal requirements, to disallow recovery of those prudent costs would be unfair and not in the public interest of maintaining adequate, reliable and economical electrical service at just and reasonable rates.

The coal ash management costs incurred to date by the Company to comply with the state CAMA legislation and the federal CCR Rule enacted and promulgated respectively in 2014 and 2015 to specify the way coal ash must be handled and stored going forward pertain to ash previously accumulated and treated in unlined basins and ponds. As discussed above, the creation or production of the ash was not unlawful or negligent and ratepayers have enjoyed the benefits of a least cost electric generation process which yielded coal ash as a waste byproduct. The Company's imprudence or negligence in the manner it handled or managed the ash byproduct did nothing to change the existence of the tons of accumulated ash or to require the present need to have this ash properly managed and in accordance with applicable law. With or without the Company's admitted negligence or its imprudence as supported by other evidence discussed hereinabove, the Company would be required to do whatever is reasonably necessary not only to comply with current applicable law but also to manage all existing and stored ash with due care to avoid the unreasonable risk of harm to persons, property and the environment. The heightened standards for coal ash management mandated by the changes in federal and state law under the CCR Rule and CAMA, as with any governmental action, are beyond the control of the Company. The Company has no choice but to comply with such new requirements, notwithstanding the Company's compliance with the prior law, and is expected to so comply as part of its ongoing certificated franchise to provide electric service. If twenty years from now the standards for ash management were to change yet again, the Company at that time would still have no choice but to comply and the costs incurred to take reasonable compliance actions relative to the very same ash being moved and stored today would then be appropriate to be recovered from ratepayers in electric service rates.

To state it another way, even in the case at hand where the evidence establishes that the Company was imprudent in its handling of coal ash, the Company's imprudence did not cause or change the fact that all of the coal ash at issue exists today and would be subject to new environmental and safety requirements. Moreover, with or without passage of CAMA, the Company would still be legally required to prudently manage its existing as well as its hereafter created ash. Based on current federal law, the technology known today and as logically follows from information and discussion in the Sutton report, such prudent handling would without a doubt require utilizing all three compliance mechanisms of making beneficial use of accumulated ash, using cap in place techniques, where appropriate and legally permissible, and moving of some substantial amount of stored coal ash from unlined to lined facilities.[6] CAMA did not change the accepted methods for proper management of coal ash; rather it incorporated those known methods into law. As the Company has known at least since the 2004 Sutton report and well before CAMA, it was going to have to remove ash from non-compliant unlined repositories. The removed ash would have to be put to beneficial use or placed in an acceptably lined facility and monitored for containment unless and until it was determined that the ash no longer posed a threat of harm. Therefore, in this case and going forward, the Company is fairly entitled to recover all the costs it has incurred to cap in place where appropriate under current law and to engineer and construct new lined containment facilities as well as to dewater, excavate and re-store pre-2007 ash production from unlined facilities into lined repositories.

However, as to ash first placed in unlined repositories beginning in 2007 and after, the Company is fairly entitled to recover costs that would be reasonable to implement on-site lined repositories or costs necessary to cap such ash in place. Dewatering, excavation and the "re-placement" costs of putting this ash that was produced in or after 2007 in new repositories (whether on or off-site) are not recoverable. If the Company had acted prudently by developing and implementing plans for compliant storage of ash within a reasonable time following completion of the Sutton report in November of 2004, evidence in the record establishes that it could have completed compliant on-site landfill repositories within 18 months. As Company witness Wells duly noted there can be unexpected delays in the permitting and construction process. Therefore, allowing the Company at least 24 months (from December 2004 to January 2007) to construct and deploy compliant ash repositories is reasonable and would mean that by 2007, all ash produced during or after 2007 should have and could have been managed through direct one-time placement into lined repositories; there should never have been any need to dewater, excavate and "re-place" the 2007 and post 2007 ash. Thus, the Company's reasonable costs for ash first produced in 2007 and after are only those costs for engineering and constructing the necessary lined facilities and for the ongoing costs of

[6] The five ash basins at Cape Fear are not subject to the CCR Rule given certain exclusions in the Rule. Three of the basins at H.F. Lee are excluded from the federal CCR Rule as well.

storing and monitoring of the ash once in the new compliant repositories. This ash should have gone from production and collection directly into compliant repositories without needing to be handled a second time and placed into a second repository. The rates previously collected from the ratepayers presumably would have paid for this initial ash handling just as they paid for the ash when it was first placed in the non-compliant unlined basins and ponds. It follows that dewatering and excavation costs for the tons of ash created from 2007 and after would not have been incurred except for the Company's ash mismanagement and negligence, resulting in the need to handle the ash a second time.[7] The engineering, construction and continued storage and monitoring costs are allowable for recovery because these costs were not created by the Company's imprudence, would have been incurred as proper ash management costs without regard to the Company's failure to act sooner to place the ash in an appropriately lined facility as required by due care and current regulation, and have not been previously paid for by the ratepayers.[8]

In addition to the engineering, construction, dewatering, excavation, storage and monitoring costs discussed above, the Company seeks to recover all the transportation costs (minus $9.5 million to transport ash from the Asheville plant, which the Company agreed was reasonable to question) it has incurred to date to truck or haul coal ash from its Sutton and Asheville plants' on-site repositories to off-site locations. The Company should not be entitled to recover these transportation costs (pre-2007 ash nor 2007 and after ash) from the ratepayers because they flow directly from the Company's negligence in its coal ash management and its failure to use reasonable due care to protect life, property and the environment from harm after it knew or should have known that coal ash posed a serious risk of contamination of surface and groundwater and after it knew or reasonably should have known that its repositories were not adequately containing the ash contaminants. Whether CAMA led to the Company's reasoned perception and judgment that it needed to incur trucking, hauling and preparation-to-haul expenses in order to comply with timeline requirements in CAMA, there nevertheless would not have been any or hardly any transportation costs at all if the Company had not mismanaged

[7] While it may be that the total coal ash management costs sought to be recovered may have been less had the Company not negligently delayed converting to lined ash ponds after the Sutton report was completed, the evidence in the record is that it is nearly impossible and probably highly speculative to determine how much less given the passage of time and a number of other complexities and unknowns. Nevertheless all existing ash is subject to the legal requirement that it be properly stored under the provisions of the CCR Rule and CAMA. The heightened handling and storage standards imposed by law and regulation are for the public benefit and are in the public interest. In balancing the interests of consumers and the utility, I find that rates including the reasonable cost of proper containment of ash but excluding dewatering and moving costs associated with ash created in or after 2007 and further excluding transportation costs (as will be discussed in the following paragraph) is just and reasonable. Such rates fairly balance the consumer's and the utility's interests considering the benefits received and the costs reasonably incurred to properly store and manage ash in accordance with new lawfully imposed standards.

[8] The Company and the Public Staff would be charged with assuring that the ratepayers are not charged twice for the same handling and management costs with respect to the ash produced during or after 2007.

its coal ash management obligations and negligently failed to take action to move all ash to on-site lined repositories at the Sutton and Asheville plants when it knew the ash contaminants were not being adequately contained within the repositories and that unlawful and/or violative discharges and exceedances from the repositories that could impact both surface and groundwater were occurring. Looking at the situation as it existed in 2004, the Company should not have been paralyzed and unable to take reasonable actions to move toward compliant containment of accumulated ash and ash being produced at the time by the fact that environmental regulators had not yet created the specific guidance such as that later found in the CCR Rule and CAMA legislation.

As previously discussed, the Company acted imprudently not to have taken steps after learning of the information in the Sutton report in 2004 and not being prepared to move all pre-2007 ash from unlined repositories at least starting by 2007. Moreover, in 2007, the Company had knowledge that some of its unlined facilities were experiencing exceedances and that the Company was knowingly incorporating the use of unpermitted seeps into its coal ash management practices. If the Company had acted prudently to be in a position to have begun dewatering, excavating and moving pre-2007 ash into lined on-site plant landfills by 2007, it would have been "CAMA compliant" at least with respect to its active basins and ponds before the enactment of CAMA.[9] As explained by Public Staff witnesses Garrett and Moore, on-site remediation is generally the most cost-effective closure method and would certainly not be as costly as securing other locations and transporting off-site to those locations. (Tr. Vol. 18, p. 140.) Timely development and use of compliant on-site landfills beginning around 2007 would have completely eliminated the need for the transportation and hauling costs (for both pre-2007 ash and 2007 and after ash) that the Company found necessary to meet compliance timelines contained in CAMA.[10] In my view it is not necessary to determine whether the Public Staff's witnesses are correct that compliance with CAMA did not necessitate transportation or hauling of ash or that the hauling costs should have been less in order to determine from the greater weight of the evidence in the record that the transportation costs (not to be conflated with dewatering and excavation costs as discussed above) were

[9] Costs related to inactive basins are not part of the costs sought in this case and I am not addressing what would have been reasonable for management of inactive repositories during the 2004 to 2007 timeframe.

[10] There is disputed testimony in the record on whether an on-site landfill could have been constructed at the Asheville plant due to the provisions of the Mountain Energy Act of 2015. If the Company had acted prudently by 2007 to create a compliant on-site landfill at the Asheville plant, the landfill would have been completed prior to enactment of the MEA. The new units contemplated by the MEA would have been planned around the newly constructed basin—not the other way around.

caused by the Company's imprudence, i.e., mismanagement and negligence,[11] in delaying action to correct the issues identified in 2004.

Having determined which costs should be recoverable in rates and which should not, I would allow the recoverable portion to be amortized over seven years (as an unusual or extraordinary expense), with the unamortized balance included in rate base.

/s/ ToNola D. Brown-Bland

Commissioner ToNola D. Brown-Bland

[11] CAMA left the choices and decisions of how best to achieve compliance in a timely manner to the plant/basin owner. I do not take issue with the Company's decision to transport and store ash off-site for compliance purposes, as generally the Commission should avoid substituting its judgment for the Company's business judgment. It is accepted that the Company had several possible workable options to choose from in deciding how best to comply with CAMA and that the Company chose the option[s] it found most appropriate considering a host of information available and pertinent to it at the time. I do not believe the Company chose to haul ash over public roads, creating greater risk of exposure to liability, on the hope of receiving some level of return on any additional expense incurred to do so.

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DOCKET NO. E-2, SUB 1153

Commissioner Daniel G. Clodfelter, concurring in part and dissenting in part:

I. MATTERS ADDRESSED IN THE PARTIAL JOINT STIPULATION

With respect to those matters addressed by the partial joint stipulation negotiated between the Company and the Public Staff, I am in substantial agreement with the majority's disposition of those items. I write separately with respect to the topics addressed by the partial joint stipulation for two reasons. First, there is one matter as to which I would reach a different result than the stipulating parties and the Commission majority. Second, because the partial stipulation deals with some topics only in a conditional, preliminary, or contingent manner, or because they are resolved by the stipulating parties for purposes of settlement of this case only and without prejudice to positions that may be asserted in future cases, I wish to offer my own individual views as a supplement to the majority's analysis, in the hope that such insight may be useful to the parties in future cases.

A. Cost Allocation and Cost of Service

As the Commission majority notes, for the allocation of demand-related costs, the historical position of the Public Staff has been to support the use of the Summer/Winter Peak and Average (SWPA) methodology. This position has been favored by the Commission itself in prior general rate cases. See, e.g., Order Granting General Rate Increase, Docket No. E-2, Sub 1023 (May 30, 2013); Order Assessing Rate of Return Penalty and Granting Partial Increase in Rates, Docket No. E-2, Sub 444 (September 24, 1982). In the partial stipulation in this case, as in the Company's prior 2013 general rate case, the Public Staff has agreed – for purposes of settlement of this case only – not to object to the use of the Summer Coincident Peak (SCP) methodology for allocation of demand-related costs. The stated rationale for this acquiescence is that the Public Staff has concluded that, in the present case, the two different methodologies do not yield materially different results. (Tr. Vol. 19, p. 97; Public Staff Floyd's Late-Filed Ex. 1.) One might well ask why this fact is not instead a good rationale for insisting on the historic preference for the SWPA methodology. The answer lies, of course, in the fact that other stipulating parties and several of the intervenors do not support the SWPA methodology. Neither, though, do they all concur in the use of the SCP methodology, with some parties advocating for the use of a Winter Coincident Peak (WCP) method or even consideration of a dual Summer-Winter Coincident Peak method. In the resulting negotiations, it appears that the SCP method provided a point of agreement among the greatest number of the parties. Underlying the parties' differences are divergent views about the implications of two factors -- the Company's transition from summer planning to winter planning for resource development purposes and the developing evidence of a shift in the Company's peak loading from summer to winter. These trends appear likely to continue, and the Company, the Public Staff, and other parties may benefit from more explicit direction and guidance from the Commission as to its preferred methodology for allocation of demand-related costs. I would hope that the rationale for supporting one methodology over another can receive more attention in the Company's next general rate case. To that end, I would modify ordering paragraph 28 of the Commission's order to require that the Company, in its annual cost of service filings, include an allocation based on the WCP method, as well as the SWPA and the SCP methods.

The second topic concerns the methodology for apportioning distribution system costs among different customer classes, a subject that indirectly enters into rate design as one of the considerations in setting the basic or fixed customer charge component of billing. Several intervenor parties presented testimony highly critical of the Company's method of implementing its minimum system methodology for apportioning distribution system costs, calling into question, among other things, differences in the outcome of the Company's application of that method and the outcomes achieved by other integrated, investor-owned electric utility companies employing the same method. The testimony of witness Barnes was particularly focused on this discrepancy. (Tr. Vol. 16, pp. 57-67.) The Company's rebuttal testimony did not respond in detail to these criticisms.

In evaluating the Company's use of the minimum system method for allocating distribution related costs, I believe it is also important to recognize that the Company's substantial projected investments in its Power/Forward Carolinas grid modernization program means that distribution system cost allocation among customer classes will take on heightened importance in future rate cases. If the Company is using a suboptimal methodology for allocating these costs or is incorrectly applying an otherwise acceptable methodology, the follow-on implications for rate design could be very significant in the future. For this reason, as in the case of the methodology for allocating demand-related costs, I again believe that the Commission, the Public Staff, and all other interested parties would benefit from a more focused and explicit evaluation of optional methods for distribution system cost allocation and an assessment of the extent to which any single allocation methodology is being consistently applied by the utilities using it.

In summary, I believe that changing trends in resource planning and resource demands plus a planned major reconstruction of the Company's distribution system combine to warrant a more formal examination and expression of Commission policies with respect to matters of cost allocation. Continuing to leave those matters to stipulated settlement on a case-by-case basis risks uncertainty for the Company and its customers, as well as inconsistencies in the application of cost allocation principles among the various regulated utilities. While the technical workshop on grid modernization the Company has committed to conduct in Paragraph IV.A. of the partial joint stipulation will be a useful first step in fleshing out some of the questions about cost allocation that may be generated by the Company's proposed distribution system investments, I am doubtful that the workshop will by itself provide sufficient opportunity to explore in depth many of the issues that surfaced in the testimony of witnesses Simpson, Barnes, Golin, Alvarez, and O'Donnell. The Commission majority has for now reserved judgment on whether to initiate a separate docket on the Company's grid modernization plans; I anticipate that question will be before the Commission again after the technical workshop.

B. Per Customer Fixed Charge

The point just made is one part of the reason I would refuse to accept Paragraph IV.F.3.a. of the partial joint stipulation, and would instead decline to authorize any increase in the per customer fixed charge at this time. The case for exercising caution in increasing the fixed portion of customer charges is well set out in Resolution 2015-1 adopted by the National Association of State Utility Customer Advocates (NASUCA), and I will not repeat here the considerations identified and expressed in NASUCA's resolution. (Ex. Vol. 19, pp. 286-289.) Certain additional factors counsel the same caution in this case. Until there is greater clarity as to how the Company's planned grid modernization investments will affect distribution system costs, it would be premature, I think, to assess how, if at all, the fixed customer charge should be changed. Leading me to the same conclusion, Company witness Wheeler testified that it is his expectation that implementation of the Company's proposed AMI metering system, when combined with the greater flexibility and data management capabilities of the Company's new customer information and billing system, will open opportunities for new and more creative rate designs. (Tr. Vol. 10, pp. 225-228.) In my view, these opportunities should include, among others, ways to address internal subsidization within the residential rate class between low- and high-usage customers, a better method for recovering distribution related costs from net metered customers, and ways to provide additional relief and support for customers who have difficulty paying their bills.

As for this last group of customers, I note that while the partial stipulation between the Company and the North Carolina Justice Center provides for an additional contribution of $2.5 million by the Company to the Helping Home Fund (Fund) for low-income customers. While this is commendable and something I support, mechanisms such as the Fund are imperfect and are not the most desirable means for addressing the impact of electricity cost increases on low-income customers. Innovative rate designs made possible by the Company's deployment of AMI and new customer information and billing systems could be of wider and more sustained benefit to this particular customer group. They could present opportunities for the Company to consider programs similar to the Percentage of Payment Plan and the Residential Service Low Income rate offered by the Company's Duke Energy Ohio affiliate. Again, given the expectation that these developments may or will affect the setting of the per customer fixed charge, I would support deferring any decision to allow a change to the basic customer charge at this time.

II. COAL COMBUSTION WASTES – GENERAL MATTERS

The Company's request to recover costs incurred since 2015 associated with permanent disposal of coal combustion residuals located in nineteen active or inactive surface impoundments at the Company's eight coal-fired plants in North and South Carolina, and to include ongoing and future costs of disposal in its present retail rates, presents a host of difficult questions, many of which have been only infrequently addressed, if at all, in prior rate cases.[1] The Commission has in past cases addressed the recovery in rates for utility investments in abandoned or cancelled generating plants. See, e.g., State ex rel. Utilities Comm'n. v. Thornburg, 325 N.C. 463, 385 S.E.2d 451 (1989) (Thornburg I); State ex rel. Utilities Comm'n. v. Thornburg, 325 N.C. 484, 385 S.E.2d 463 (1989) (Thornburg II). However, the matters at issue in this case differ from such investments in that they involve present and future expenditures incurred and to be incurred to dispose of wastes produced over many years from the generation and sale of electricity to several different generations of customers. As far as I am aware, the Commission's only published decision involving similar facts occurred in connection with a request by Public Service Company of North Carolina (PSNC) to recover costs incurred to remediate environmental contamination at several decommissioned manufactured gas plants owned and formerly operated by it. See Order Granting Partial Rate Increase, Docket No. G-5, Sub 327 (October 7, 1994) (1994 PSNC Order). Even this precedent, at least so far as the published opinion discloses, did not address many of the most ardently contested issues in the current case. To mention only one prominent difference, there is no indication in the 1994 PSNC Order that the PSNC's history of management of the manufactured gas plants and associated environmental compliance involved any instances of criminal misconduct. In part because the facts of this case do not neatly conform to any prior precedent, I have chosen to write separately from the majority to set out my own views as to the appropriate disposition of the issues in this case.

In several important respects, I reach different conclusions from those of the majority, but in others, I am in accord with the Commission majority for the reasons stated in its opinion. Before turning to my areas of disagreement, I will briefly recap the matters where I concur:

> First, I believe the majority correctly determines that the costs incurred to comply with the EPA's Coal Combustion Residuals Rule (CCR Rule) and with North Carolina's Coal Ash Management Act (CAMA) should be recovered on a system basis and not solely from North Carolina retail ratepayers.
>
> Second, for the reasons stated in the majority's opinion, I agree that allowed costs should be allocated among retail customer classes based on an energy usage factor and not based on a demand factor, as requested by the Company and some of the intervenors.
>
> Third, I concur in the majority's determination that the Company's proposal to recover as part of its fuel costs some $13.8 million for offsite disposal of ash

[1] Although I was not a member of the Commission and thus did not participate in the 2016 consideration of Dominion North Carolina Power's request, in Docket No. E-22, Sub 532, to recover similar waste disposal costs, for reasons set out in the majority opinion, I agree that the ruling in that case rests on materially different facts and considerations and, therefore, is not precedent for this case.

wastes from its L.V. Sutton plant at Charah, Inc.'s Brickhaven facility in Chatham County may not be recovered under G.S. 62-133.2(a1)(9) for the simple reason that no "sale" of the waste by the Company occurred.

Finally, I agree with the majority's conclusion that it would be inappropriate to allow the Company to recover in its present rates those costs yet to be incurred for future disposal activities relating to the coal combustion residuals at the eight plants. Although the Company has offered its best projection on its expected year-by-year expenditures going forward, the Company's witnesses conceded that there was some measure of uncertainty in those projections, if for no other reason than that the volume of combustion wastes in each of the nineteen impoundments is not yet known with certainty, and disposal costs will vary according to the quantities finally determined. Also, as I note later with respect to the Roxboro and Mayo plants, regulatory approval has not yet been secured for the Company's plans for some of the waste impoundments, and the outcome of those approvals may significantly alter the Company's present cost estimates.

A. Framing the Issues – Part One

Following the precedent of the 1994 PSNC Order, I believe the Commission should consider both whether the Company's expenditures to comply with current law were reasonable and prudent as to the elements and the amount of the expenditures, and also whether the Company's history of design, construction, operation, and maintenance of the waste impoundments were reasonable and prudent. The Company's position appears to be that the first of these inquiries is dispositive in itself. I do not agree. It is worth noting that the Commission observed, in the 1994 PSNC Order, that PSNC had handled the wastes and byproducts from the gas manufacturing process in accord with laws applicable at the time. See 1994 PSNC Order, at p. 20. That fact, however, did not lead the Commission to conclude that it was therefore unnecessary to undertake a review of the reasonableness of PSNC's operation of the plants before they were finally closed.

Left unresolved by the 1994 PSNC Order, at least so far as the order itself discloses, is the matter of reconciling the outcome of the two determinations if the results diverge. Consider that if the Commission were to conclude that both the fact and the amount of the current expenditures for ash disposal are reasonable and prudent and that the Company's historical handling of the coal combustion wastes also was reasonable and prudent, the need to resolve conflicting determinations does not arise. Likewise, if the Commission were to conclude that the historical operation of the waste impoundments was reasonable and prudent but that some or all of the proposed current expenditures for closure and permanent disposal of the combustion residuals were not reasonable and prudent, either in fact or in amount, then the Commission would disallow some items or amounts and allow others, but would not look further.

The more difficult case is the one which I believe arises on the evidentiary record as it stands. With limited exceptions as to specific items challenged by the Public Staff, none of the objecting intervenors has questioned the reasonableness of the items of expenditure or the amounts of those expenditures that the Company proposes to recover on account of its efforts to comply with current law relating to the disposal of coal ash wastes. However, using several different theories, emphasizing various different pieces of evidence, and proposing several different remedies, the Public Staff, the Attorney General's Office (AGO), and all of the objecting intervenors have challenged the reasonableness and prudence of the Company's historical management of coal combustion wastes. In so doing, they have presented the Commission with the task of deciding from the record how, to what extent, and in what amounts the Company's history of waste management affected or impacted, if at all, its current and expected future expenditures for permanent disposal of the coal combustion residuals. This is not a simple determination, and it will occupy much of my remaining discussion.

B. Framing the Issues – Part Two

A second challenge centers on proper characterization of the items of cost associated with disposal of ash wastes for purposes of applying G.S. 62-133. Here, the difficulty comes from the tendency of all parties to speak about the wastewater impoundments where most of the wastes are now stored as being in the nature of "property," or "plant," or "facilities" within the scope and meaning of G.S. 62-133(b)(1). While this manner of speaking and thinking is understandable, it is strictly correct only insofar as the impoundments are now or were formerly used and useful for the treatment of the wastewater used to flush coal combustion residuals from the generating facilities before recycling the water for other plant uses or discharging the treated wastewater to nearby surface waters.[2] However, it is not the impoundments themselves that are at issue in this proceeding; instead, it is the ash wastes that have accumulated in them. The costs the Company has incurred and will continue to incur arise not from the impoundments *per se*, but instead from the need to permanently dispose of the waste combustion residuals that have accumulated in them. In my view, costs to dispose of waste products generated from the burning of coal are very plainly operating expenses within the meaning of G.S. 62-133(b)(3). Those waste products are not in any sense "property," "plant" or "facilities" comprehended by G.S. 62-133(b)(1). Consider that disposal of these wastes can occur in several ways. They may be sold for beneficial reuse as structural fill, mine reclamation, additive for concrete, or for other uses. They may be removed for permanent disposal offsite in landfills owned by a third party. Certainly none of such disposal methods would involve the Company's "plant" or "facilities." Permanent disposal of the wastes on the Company's own property, in a landfill, or in a properly closed impoundment that was formerly used for wastewater treatment purposes are other methods of disposal of the wastes, but those methods of disposal do not convert the disposal costs from being treated as operating expenses to being treated instead as investment in "plant" or "facilities." I emphasize this point primarily because proper

[2] Some of the impoundments also were used to treat wastewater streams originating from plant processes other than coal combustion.

characterization of the costs at issue is, I believe, an important first step in determining how those costs should be allowed and recovered.

C. The State of the Record

On the questions thus framed, the state of the evidentiary record leaves something to be desired. The Company presented no witness with first-hand knowledge or experience regarding its waste ash management policies, decision-making, or operating practices prior to 2014. Company witness Kerin provided clear and comprehensive testimony concerning the Company's decision-making and activities with respect to coal combustion residuals after his assignment to the issue in 2014, but he came to his task with no prior experience relating to the issue. Company witness Wells gave informative and knowledgeable testimony concerning the Company's history of environmental compliance, but only for the period after 2009. Company witness Wright had no prior education, training, or experience with the management of coal combustion residuals, and his testimony largely consisted of opinions on matters of interpretation of law and legal inference, which are in any event the province of the Commission itself and not subjects for witness testimony.

From the Public Staff and intervenors, only AGO witness Wittliff had first-hand knowledge and experience of ash waste handling practices during the time period prior to 2000 and extending back to earlier decades. His experience, while certainly relevant and highly important in evaluating the Company's conduct, was based only on a review of Company records and documents produced in discovery and did not involve a first-hand inspection of any of the waste impoundments or contemporaneous knowledge of the Company's historical activities. Even so, I find witness Wittliff's overarching opinions and conclusions to be entitled to substantial weight, especially in the absence of contrary testimony from any other witnesses with more direct knowledge.

Much of my own evaluation and assessment, therefore, depends on documentary evidence which itself has many gaps, especially in regards to the operating history of the individual waste impoundments at the Company's eight plants. The state of the evidentiary record is, I believe, in large part a consequence of the framing of the issue by the Company, as explained above. If the reasonableness and prudence of the Company's proposed cost recovery is limited solely to examination of the items of expenditure and the amount of expenditures incurred by the Company to comply with CAMA and the CCR Rule from and after the date of enactment of those regulations, then it is not necessary to present extensive evidence concerning the decisions, policies, and operating practices that occurred over the many years prior to the adoption of the CCR Rule and the enactment of CAMA. As already noted, I think this framing of the issue is incorrect, but that conclusion then requires an answer as to what the Commission should do about the state of the record. There are, I think, several possible responses.

One is to accept the often-repeated conclusory testimony of the Company's witnesses, that during the decades prior to 2014, the Company's management of wastes from the burning of coal was reasonable and prudent and in accord with prevailing industry standards and practices. I find this testimony, especially coming from witnesses with no experience of the matter and which merely restates the ultimate issue to be decided, to be unacceptable. In large part, I am compelled to do so because the conclusory statements of the witnesses simply cannot be reconciled with the Company's admission in the federal criminal cases that it had been criminally negligent over a period of at least several years with respect to the matters charged, meaning that it failed to exercise the degree of care in the management of the waste impoundments that a reasonably prudent person would have exercised. As the Company's counsel explained in his address to the District Court: "I want to talk for a second about the kinds of crimes that the company has acknowledged and pleaded guilty to. These are crimes of negligence. These are negligence-based crimes." (Err. Ex. Vol. 15, p. 61.)

A second approach would be to conclude that the Company has failed to carry its burden of proof as to the reasonableness and prudence of its historical coal waste management policies and practices. In its post-hearing briefing, the Company points out that under the prevailing procedural and evidentiary standards, the Company's expenditures should be presumed to be reasonable and prudent until an objecting party steps forward with evidence suggesting to the contrary, at which point the Company bears the burden of proof to substantiate the reasonableness of the expenditures. The Company argues that no party other than the Public Staff satisfied the initial prong of this procedure, and that the Public Staff did so only with respect to the discrete items of expenditure recommended for disallowance by witnesses Garrett and Moore and by witness Lucas. I believe that the precedents cited by the Company are inadequate to carry the weight of the burden such precedents place upon them. When the matter under review involves the reasonableness and prudence of a known and discrete expenditure made at a definite point in time, it is appropriate to require that parties challenging that expenditure come forward with some evidence that reasonable alternatives were available and to quantify the amount of the alleged error. See State ex rel. Utils. Comm'n v. Conservation Council of North Carolina, 320 S.E.2d 679, 312 N.C. 59 (1984). In this case, the challenges made by the Public Staff, the AGO, and the intervenors, except in the case of specific items of expenditure challenged by the Public Staff, do not involve discrete, known items of expense but are instead matters of omission, inaction, inattention, neglect and delay. From the very nature of the errors asserted by the objecting parties, it is not possible to reconstruct hypothetical histories and then, today, after many years, reconstruct the costs that might have been incurred under those alternative histories. I would find that there was ample evidence presented by several of the intervenors, by the AGO, and by the Public Staff, to put at issue the reasonableness and prudence of the Company's historical coal waste management policies and practices and thereby require the Company to carry its burden of proof on that subject.

The consequences of adopting the second approach and denying the Company all cost recovery for failure to carry its burden of proof would have severe financial consequences for the Company and would, as the majority points out, likely lead to the Company's having to pay even higher costs to secure equity and debt financing for future operations and investments, a result that would significantly harm ratepayers. It would, I believe, fail the fundamental test set out in G.S. 62-133(a), requiring that the

Commission's determination of rates be fair and reasonable not only to objecting parties and ratepayers, but also to the Company.

Complete disallowance of all coal ash disposal cost recovery on the ground that the Company has failed to carry its burden of proof also flies in the face of common sense. Had the Company's management of coal combustion wastes resulted in no exceedances of the state's 2L groundwater standards, no violations of any NPDES permits, no criminal prosecutions, and no civil or administrative lawsuits, the record taken as a whole shows that the Company would eventually have been required to undertake many or even most of the ash disposal activities now required of it by the CCR Rule and CAMA. As evidence for this, I refer to the Company's 2004 study and report concerning options for long-term management of combustion residuals at its L.V. Sutton plant, which I consider to be one of the more important documents admitted into evidence in this case. (Ex. Vol. 22, pp. 165-211.) The 2004 study was authored *before* the Kingston, Tennessee, ash spill in 2008, *before* the promulgation of the initial drafts of the CCR Rule, *before* the administrative actions commenced by the North Carolina Department of Environmental Quality (DEQ) against the Company in 2013, *before* the 2014 spill at Duke Energy Carolinas, LLC's Dan River plant, *before* the adoption of the final CCR Rule, and *before* the adoption of CAMA. As the study discloses, even in 2004, when the regulatory regime was defined by the Clean Water Act and NPDES permits issued pursuant to that statute, by Part D of the Resource Conservation and Recovery Act, and by state regulations implementing those two statutes and imposing the 2L groundwater standards, the Company had developed the view that eventual closure of the existing impoundments would be required either by dewatering the impoundments and capping the ash in place, or by excavation of the ponds and disposal of the combustion wastes in dry landfills. As subsequent events proved out, the Company's assessment in 2004 turned out to be absolutely correct.

The third approach, and the only one I would find proper under the circumstances of this case, is to grapple with the available evidence, most of it documentary, in order to form a best judgment as to whether the Company's history of management of coal wastes is so flawed as to render its present expenditures for permanent disposal of those wastes unreasonable and, if so, how to quantify the effects of the past on the present. On the record as it stands, I believe the only way to undertake these two tasks is to consider the evidence on a plant-by-plant basis, and I attempt to do so in later sections of my opinion. First, though, a short discussion about the standard of care I believe should be applied in assessing the Company's actions and omissions.

D. The Standard for Evaluating the Company's History

Company witnesses and opposing Public Staff and intervenor witnesses alike concurred that regulatory standards and customary industry practices for handling and disposal of coal ash wastes have evolved over an extended period of years. (See, e.g., Ex. Vol. 16, p. 211; Tr. Vol. 16, pp. 109-135.) The question the Commission must consider is whether the Company acted reasonably in response to, and in light of, those evolving standards. This is made more difficult by the long period of development of scientific and environmental understanding and regulatory interest in coal combustion waste between the time of the Company's general rate case in 1987 and its next-but-this rate case in 2013. However, I believe that the record taken as a whole clearly reflects that, during that twenty-six year period, both "best practices" and regulatory requirements with respect to ash wastes advanced in a direction that converges toward the present mandates embodied in CAMA and the CCR Rule.

When environmental regulations prohibited discharge of fly ash from stacks, two methods of handling that ash developed. One, which had long been used with respect to bottom ash (including by the Company itself) was dry handling, which involved manual removal of the collected ash followed by dry disposal in either a lined or unlined landfill, land application, or dry stacking of the wastes. The second method involved using water to flush the accumulated ash, bottom ash and fly ash, and other combustion by-products, from the generating plant. The resulting ash laden wastewater was sluiced to detention ponds where the ash was allowed to precipitate and settle out, thereby permitting discharge or reuse of the treated wastewater. After enactment of the Clean Water Act in 1972, the regulatory regime applicable to wet handling of coal combustion residuals was primarily intended to address treatment of the wastewater before discharge and not the ultimate disposal of the waste ash itself. Hence the impoundments themselves should be considered – as they are and were treated under the Clean Water Act - as wastewater treatment facilities, not as permanent facilities for disposal of the waste combustion residuals.

The record establishes that the different environmental risks associated with wet handling of ash and the resulting accumulation of precipitated ash in the wastewater treatment basins, as compared with dry handling followed by permanent disposal of the ash in landfills, were well understood as far back as the time of the enactment of the Clean Water Act. When left in standing water, unprotected from rainfall or storm water runoff from surrounding areas, in impoundments that were not hydrostatically isolated from groundwater, there is now and was then a risk that constituents in the waste ash would migrate into groundwater or seep to the surface outside the impounded area. These are fact of elementary chemistry, hydraulics, and hydrology; they were not something awaiting discovery in some new scientific breakthrough.[3]

At all points after the time the emission of waste fly ash from smokestacks was prohibited, the Company had a choice between dry and wet methods of handling

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[3] In 1979, a researcher at the Los Alamos Scientific Laboratory submitted a report at the Environmental Technology Training Conference in Arizona, titled "The Disposal and Reclamation of Southwestern Coal and Uranium Wastes," which contained the summary conclusion that "[t]here is growing awareness that the discarded wastes from coal combustion are a serious potential source of surface and ground water contamination." (Ex. Vol. 22, p. 224.) The author of the report cited to a number of other contemporaneous papers and reports on the subject. Although no Company witness testified to personal knowledge of this report, it is indicative of the general state of knowledge at the time. The applicable standard is, in any event, not what the Company actually knew, but what it reasonably could and should have known. See 78 North Carolina Utilities Commission Orders and Decisions 238, pp. 251-252 (August 5, 1988).

combustion wastes.[4] Although the applicable regulatory regime permitted the Company to choose between these two methods, that fact does not mean that their environmental and regulatory risk profiles were the same, nor does it absolve the Company from its obligation to implement its chosen method in a reasonable and prudent manner in light of the specific risks inherent in that method. The knowledge that is to be charged to the Company during the last four decades of the twentieth century, and the first two decades of this one, is not knowledge of what actions legislatures and regulators might take at some future point. Instead, the knowledge that the Company is charged with is knowledge of the different environmental consequences of dry management of ash in landfills or mineshafts versus wet management in wastewater treatment ponds, and these differences are matters of basic chemistry and hydrology. The Company's inability to predict regulatory and legislative developments does not mean it was unable to understand and foresee the environmental consequences of improper design, construction, operation, repair, and maintenance of the surface impoundments it chose to use for treatment wastewater laden with coal ash wastes.

The Company cannot disclaim contemporaneous knowledge of the basic differences between wet and dry handling of waste ash. As early as August, 1978, in connection with its review of the Company's proposal to construct an ash settling impoundment in the upper reaches of Crutchfield Branch at the Mayo plant, the North Carolina Department of Environmental Management advised that it was the State's intention to require that the Company "… provide controls as necessary for the prevention of pollutant materials from entering ground water and thereby reentering the surface waters some point downstream of the proposed dam," and further that the Company "…provide such testing as is necessary to assure that pollutants are not discharged to the ground waters and thereby to the downstream point of the Crutchfield Branch …" (Ex. Vol. 22, pp. 216-217.) More generally, the Company's NPDES permits issued under the Clean Water Act contained certain standard conditions the Company was obligated to comply with, including the following:

> a. The Permittee shall take all reasonable steps to minimize or prevent any discharge or sludge use or disposal in violation of this permit with a reasonable likelihood of adversely affecting human health or the environment…
>
> b. The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related

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[4] In its 1988 report to Congress on the question of whether coal combustion wastes should be regulated as a hazardous waste under Subpart C of the Resource Conservation and Recovery Act, the EPA notes that, by that date, the most common method of disposal of waste ash throughout the United States was in dry landfills. While surface impoundments were also very common, their use was concentrated in the southeastern United States where, the EPA noted that access to sufficient, affordable water can make surface impoundments a realistic, economic option. (Tr. Vol. 16, pp. 220-225; Ex. Vol. 21, pp. 513-516.)

> appurtenances) which are installed or used by the Permittee to achieve compliance with the conditions of this permit…

(Ex. Vol. 17, p. 378; see also 40 C.F.R. § 122.41.) The Company, having chosen a method for waste handling that was known to have a potential risk of contamination of groundwater and surface water, I conclude that the degree of care expected of the Company in its management of the wastes should have been commensurate with that risk. Put differently, the standard of care expected of a reasonable and prudent utility is not now, and was not in the past, the absolute minimum necessary to avoid criminal prosecution or sanctions for violation of civil law; it was instead to take such actions as could or should reasonably have been taken at the time to minimize the risk that contaminants from coal ash waste would enter groundwater or surface waters.

Against the argument that the Commission's function is to be an "economic regulator," and not an "environmental regulator," I would respond that the position I have taken here is not tantamount to advocating that the Commission should substitute its judgment for that of DEQ or the federal EPA; it is just the very simple point that "reasonableness" for purposes of G.S. 62-133(b)(3) means something more than just not getting caught or, if caught, not getting prosecuted, fined, or sanctioned. Otherwise, there is really no way to carry out the General Assembly's declared policy that one purpose of the regulatory regime established in Chapter 62 is "…to encourage and promote harmony between public utilities, their users and the environment." G.S. 62-2(a)(5).

I would find from the record taken as a whole that the Company's history of managing wastes from burning coal to produce electricity contains significant and non-trivial evidence of inattention, inaction, and neglect in maintaining the wastewater treatment impoundments where the wastes were allowed to accumulate over a period of years, and that the Company was slow to take up and apply evolving best practices as they developed over time. From the very nature of unlined surface impoundments and the way water-borne contaminants enter groundwater and then migrate to surface water, any improper siting or construction of an impoundment or lax and inconsistent maintenance will have consequences that may become readily apparent only over an extended period of time. The parties focused their evidentiary presentations largely on events that occurred in the two most recent decades, most especially centering on the events that formed the predicate for the Company's federal criminal prosecution and the several civil administrative enforcement actions and private party lawsuits that were initiated during the same time period. The federal criminal charges against the Company use the formulation "… from at least [a recited date] …," leaving open the precise date the charged misconduct may in fact have begun. I find it plausible to infer from the character of the alleged criminal violations and from the nature of the surface impoundments themselves, as noted, that the Company's actions, inaction, and omissions did not suddenly start at some date in 2010, 2011, or 2012, or another subsequent date certain, but were instead a continuation of prior operating practices.

As I have already observed, the Company's decisions to use unlined surface impoundments to manage waste combustion residuals were not *per se* unreasonable or imprudent at the time those decisions were made. To the question of whether the Company managed those impoundments with the degree of care, attention, and skill I think was required at the time, I would answer that the record contains sufficient evidence to conclude that it did not do so, even under the regulatory regime in place prior to the CCR Rule and CAMA, as evidenced by the fact that the federal criminal prosecution and the various civil administrative actions were all grounded on the regulatory regime predating the enactment of those two regulations. That is not, however, the end of the inquiry. As the majority notes, and I agree, the overriding difficulty confronting the Commission is how to quantify the extent to which the Company's past conduct translates into present costs incurred. As I have already pointed out, precision in doing this would require the impossible construction and evaluation of several different alternative histories and realities. Neither Public Staff witness Lucas nor the AGO witness Wittliff, the two principal witnesses whose testimony extensively and persuasively attacked and challenged the Company's claim that its historical management of coal ash wastes had been reasonable and prudent, was able to provide any general or overall quantification of the financial consequences of the Company's mismanagement.

III. COAL COMBUSTION WASTES – PLANT-BY-PLANT CONSIDERATION

I would conclude that the general evidence in the record concerning the Company's waste handling policies and practices is not adequate to support an across-the-board denial of all cost recovery, but neither is it sufficient to resolve all questions of reasonableness and prudence in the Company's favor. I do believe, however, that such general evidence is informative and instructive in deciding the weight that should be given to specific evidence going to the reasonableness of particular items of cost recovery in the Company's application. Although my general conclusions support and undergird the following discussion, I base my final determinations primarily on factors specific to the individual coal-fired generating plants in the Company's portfolio. As Company witness Kerin acknowledged in his testimony, every waste impoundment is different with respect to important matters such as topography, hydrology, engineering, surrounding environment, and operating history. (See, e.g., Ex. Vol. 17, pp. 127-129; Tr. Vol. 17, pp. 62-63.)

A. L.V. Sutton Plant

The evidence is most extensive for the two impoundments at the L.V. Sutton plant, one constructed in 1971 and the second constructed in 1984. In 2014, these two impoundments contained an estimated 3,540,000 tons and 2,780,000 tons, respectively, of combustion residuals. (Ex. Vol. 17, p. 79.) By January 1, 2017, this amount had been reduced to approximately 2,600,000 tons remaining in the 1971 impoundment and approximately 2,800,000 tons remaining in the 1984 impoundment. (Ex. Vol. 16, p. 210.)

In the present case, the Company seeks to recover $116,858,895 expended between January 1, 2015, and December 31, 2016, for disposal of the wastes at the

L.V. Sutton plant.[5] The amount in contention among the parties is the disallowance of $80,513,871 recommended by Public Staff witnesses Garrett and Moore. **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]**

The Company contends that these expenses were necessary if the Company was to meet the CAMA-imposed deadline for permanent closure of the two impoundments. I would conclude that had the Company acted reasonably and prudently, it could have avoided the costs of offsite shipment and disposal to the Brickhaven site. Accordingly, I would deny cost recovery of the amount expended to prepare, transport, and then pay for permanent offsite disposal of any of the Sutton combustion residuals.

In reaching this conclusion, I rely in part on the testimony by Public Staff witnesses Garrett and Moore, who concluded that had the Company commenced construction of an onsite landfill on the same start date as it commenced transport of ash to the Brickhaven disposal site, it would have avoided the offsite disposal costs altogether. (Tr. Vol. 18, pp. 153-155.) The Company disputes witnesses Garrett and Moore's conclusion, noting that delays in receiving the necessary permit to construct an onsite landfill at the Sutton plant rendered it impossible for the Company to meet the CAMA-mandated deadline for closure of the impoundments and permanent disposal of the waste material in them. (Tr. Vol. 20, pp. 32-41, 56; Ex. Vol. 20, pp. 234-240.) The parties differ sharply on whether the Company can or should be able to avail itself of options provided in CAMA and in the federal criminal plea agreement to extend the compliance deadline to accommodate these delays. I find it unnecessary to resolve that disagreement for a more fundamental reason.

The evidence shows that by 2004, the Company recognized that the 1984 impoundment at the Sutton plant was nearing capacity and the end of its useful life, and that there were significant environmental concerns involving the 1971 impoundment. Accordingly, it undertook a study to identify options for a long-range strategy for combustion wastes at the Sutton plant. That study resulted in a report issued in November, 2004, containing a detailed analysis of both the then-current situation of the impoundments and disposal sites, in addition to alternatives for future management of ash. (Ex. Vol. 22, pp. 165-211.) According to the report, the objective was to identify a solution that would not only allow capacity for storage and treatment of coal combustion residuals from future electric generation *but would also utilize all of the ash previously deposited in the two existing impoundments*. (Id. at p. 168.) To repeat for emphasis, the study considered not only management of future combustion residuals, but also a long-term permanent solution for the waste ash in the existing impoundments.

[5] This amount, as with the amounts subsequently stated for the other plants, were provided by the Company on a system-wide basis and do not reflect the North Carolina retail allocation. They also do not include actual expenditures in 2017 through October 31, 2017.

This report considered both capacity constraints affecting the existing impoundments and known environmental concerns relating to the unlined 1983 impoundment.[6] Discussing these concerns, the report stated:

> The current environmental atmosphere is that these ponds will eventually have to be emptied and placed in a lined containment to eliminate the leaching of the ash products into the ground water system. This is an issue that is not currently being pressed, but it is anticipated that with the tighter environmental conditions it will soon become an emergent issue. This issue is aggravated by the fact that a test monitoring well located 300' from the edge of the 1983 ash pond has shown high levels of arsenic during the past two quarterly tests. This may or may not be related to the unlined ash pond.
>
> ….
>
> The plant lab personnel, plant management, the East Region engineers, and the environmental section are concerned with the ability to maintain the [NPDES] discharge permit limits of the ash pond associated with the continued running of the Sutton plant, as well as pond volume concerns.

(Id. at pp. 169-170.) According to the report, the Sutton plant needed an alternative solution for ash management in place by June, 2006. The target date was explained thus: "The 1984 ash pond is currently estimated to be non-operational due to Total Suspended Solids (TSS) limit exceedance which will cause a violation of the NPDES permit. The ash pond is expected to be un-operational by June, 2006." (Id. at p. 168.)

Unlike the majority, I find no ambiguity or uncertainty in the report about the need for immediate action, and that the identified need was not simply to add capacity for future waste handling. In the environmental analysis section of the report, the study team observed:

> The Analysis performed on each of the alternatives looked at both the current regulations and the current atmosphere related to regulatory regulations that are currently under review or have gotten an increased focus in the recent year. Unfortunately the past several years have seen an increased scrutiny in the ash storage regulatory area. While coal burning facilities are currently able to permit a new ash pond, every opportunity that regulators are allowed to look at existing sites and current practices it opens

[6] This impoundment is referred to in the report as the "1983 ash pond." In the Company's exhibits, this impoundment is not identified as such, but there is instead a reference to a 1971 impoundment. (Ex. Vol. 16, p. 210.) In the 2004 study, it appears that the reference to the unlined 1983 ash pond is meant to refer to the original 1971 impoundment and that the two are one and the same. (Ex. Vol. 22, p. 169.)

> the facility up to questions and further scrutiny. This risk was taken into account in the ranking of the alternatives.

(Id. at pp. 179-180.)

The report identified ten alternative courses of action, including a "do-nothing" option. Three involved beneficial reuse, one involved an experimental new technology, one involved off-site landfill disposal in either a private landfill or a new landfill constructed by the Company, and the remaining alternatives involved some combination of dry stacking of the ash, construction of vertical dikes to increase capacity of the existing impoundments, or construction of a new, lined impoundment. (Id. at pp. 170-179.)

The recommended, preferred alternative identified in the study was one of the beneficial reuse options, noting that it would constitute "...a proactive approach that will positively impact the environmental position of the Sutton plant, and allow the company to benefit from the creation of a revenue generating project that will create a positive public image in dealing with an environmental issue associated with fossil plant electricity production." (Id. at p. 188.) While no witness was able to testify as to exactly what was done with the 2004 report and its recommendations, it appears from the record that none of the long-term solutions considered in the report had been implemented by 2014. (See Ex. Vol. 17, pp. 131-133 (closure plan for 1971 and 1984 impoundments)) I would conclude that had the Company taken timely action in 2004 when it had concluded that action was both necessary and appropriate, or even at any other time thereafter up until 2014, the delays and time constraints cited by the Company as its rationale for transport and off-site disposal of the waste from the Sutton impoundments could have been avoided. Accordingly, I would disallow as unreasonable and imprudent recovery of those costs identified by witnesses Garrett and Moore as the costs for transport and disposal of waste ash from the Sutton impoundments to the Brickhaven site.[7]

In addition to disallowance of the costs for transport and offsite disposal, I would also disallow the amount of $6,693,390 identified by Public Staff witness Lucas representing costs for extraction wells and treatment of groundwater relating to offsite contamination originating from the Sutton impoundments. (Tr. Vol. 18, p. 279.) As is recited in the Company's settlement agreement with DEQ, these costs are for accelerated groundwater remediation going beyond the requirements under CAMA for closure of the Sutton impoundments. (Ex. Vol. 21, pp. 586-598.) The 2004 report concerning a long-term management strategy for ash wastes at Sutton noted that by that date contaminants often found in coal ash had been identified in at least one groundwater well near the 1983 impoundment, but the report drew no conclusions about the source or extent of possible

[7] I do not agree with witness Garrett and Moore's recommended disallowance of **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]** for installation of liner material that they contend was in excess of applicable regulatory requirements. (Tr. Vol. 18, p. 154.) In light of the history of offsite groundwater and surface water contamination associated with the Sutton plant, I would not penalize the Company for taking additional steps to help ensure that contaminants from landfilled wastes did not leach to groundwater after permanent disposal of the waste material.

groundwater contamination. In discussing the “do nothing” option, the authors of the report noted:

> This alternative would not alleviate the potential emergent projects associated with the unlined 1983 ash pond or the pre-ash pond disposal site, and the monitoring well issues.

(Ex. Vol. 22, p. 184.) Instead of taking timely action when it knew that action was required, the Company waited another decade, until action was forced by DEQ’s issuance of a Notice of Violation based on exceedance of the state’s 2L groundwater standards. By that time, evidence of groundwater contamination existed not only on the plant site itself but at the property boundary and offsite beyond. I would find that the Company’s failure to act in response to the recommendations of the 2004 report unreasonably and imprudently increased the risk of additional groundwater contamination and of migration of contaminants to and beyond the property boundary, and that its inaction is directly linked to the groundwater remediation costs incurred as part of its settlement of the 2014 Notice of Violation issued by DEQ.

B. Asheville Plant

The two impoundments at the Asheville plant, known as the 1964 ash pond and the 1982 ash pond, contained as of August, 2014, an estimated 2,200,000 tons and 800,000 tons of coal ash, respectively. (Ex. Vol. 17, p. 79.) By January 1, 2017, the Company estimated that the 1982 impoundment contained no remaining combustion residuals, and the 1964 impoundment contained 2,900,000 tons of ash, the difference in these figures largely resulting from the Company’s temporary transfer of ash from the 1982 impoundment to the 1964 impoundment in order to facilitate construction of its new combined cycle gas generating plant within the footprint of the 1982 impoundment. (Ex. Vol. 16, pp. 209-214.)

Controversy centering on the management of combustion residuals at the Asheville plant centered on three topics: the Company’s guilty plea to one count in the criminal indictment relating to unpermitted discharges from engineered seeps at the Asheville plant, the Company’s decision to transfer ash from the 1982 impoundment to the 1964 impoundment prior to shipment to an offsite landfill for permanent disposal, and the Company’s decision to dispose of the ash at a more distant and more expensive landfill facility in Georgia instead of using the landfill facility located at its affiliate’s Cliffside plant in North Carolina.

The action that formed the basis for the Company’s plea to one count of violating its NPDES permit for the Asheville plant is summarized in the following statement of counsel at the hearing before Judge Howard:

> …[I]t’s fair to say there is a disagreement among us about whether a seep by itself that simply percolates up and may reach a water of the United States is a violation of the law. The Government takes the position it is. That

> issue is not resolved in this plea. What the company did in this plea is it acknowledged it should not have had specific engineering structures that take seeps, pull them together and then put them into a water of the United States, unless it was part of the permit.

(Ex. Vol. 14, p. 382.) Translating "specific engineering structures" into simpler English – the unpermitted discharge was an intentional action, not simply the result of inattention or neglect. Although I would find that this admission by the Company is some evidence supporting the imposition of a penalty for mismanagement, I would not find that it affected the reasonableness of the costs the Company has actually incurred in order to permanently dispose of the waste in the two Asheville impoundments.

Several parties argued that "but for" the Company's criminal prosecution, which was based in part on the unpermitted discharges from the Asheville impoundments, the Company might have been able to dewater, cap the waste ash, and thereby close the impoundments in place, avoiding the higher costs of CAMA's mandate that the impoundments be excavated and the ash removed to a dry landfill. Drawing conclusions about "might-have-beens" is inherently difficult and is especially so when the "might-have-been" relates to legislative actions. With respect to the two Asheville impoundments, that task is rendered even more complicated because of the enactment of S.L. 2015-110 (Mountain Energy Act of 2015), which required the accelerated closure and decommissioning of the remaining coal-burning generation units at the Asheville plant. To replace those coal-burning units, the Company's only reasonable option was to excavate the 1982 impoundment and construct a new gas-fired combined cycle plant within the footprint of the impoundment. Excavation, in other words, was independently driven, at least in part, by the need to comply with the Mountain Energy Act of 2015.

On the two remaining matters in dispute relating to closure of the Asheville impoundments, I am persuaded by the Company's testimony that the timelines necessary to comply with the Mountain Energy Act of 2015 could not have been reasonably anticipated by the Company, and that such compliance required immediate removal of ash waste from the 1982 impoundment in order to enable construction of the new generating plant. The Company has acknowledged, however, that the contract prices it paid in 2015 and 2016 for transport and offsite disposal of the wastes from Asheville may have been excessive in light of later prices it was able to negotiate, and that an adjustment in the costs of offsite disposal of $9,500,000 would not be inappropriate accordingly. (Tr. Vol. 20, p. 45.) Accordingly, like the majority, I would reduce by $9,500,000 the costs of offsite disposal for which the Company seeks recovery.

C. <u>Roxboro and Mayo Plants</u>

The Company's Roxboro coal plant has two ash impoundments, known as the East Basin, constructed in 1966, and the West Basin, constructed in 1973. As of January 1, 2017, the total combined estimated amount of combustion residuals in these two basins was approximately 19.7 million tons. (Ex. Vol. 16, p. 209.) The Mayo plant has a single impoundment, constructed in 1983, which holds an estimated 6.6 million tons of combustion residuals. (Id.) These two plants are still in operation and the three impoundments are still receiving ash and combustion residuals from the burning of coal to generate electricity for current customers.

To date, the Company has expended a total of $14,867,363 to prepare and submit to DEQ a plan for closure of the Mayo impoundment, including preparation of engineering plans and cost estimates. (Ex. Vol. 16, p. 268.) For the Roxboro plant, the Company has expended and seeks recovery of $20,370,325 for the same activities. The closure plans for all three impoundments call for leaving the combustion residuals in place, installing a cap over the waste material, and taking other steps to guard against migration of ash from the capped impoundments. The Company is not now seeking recovery of any costs for implementation of its proposed closure plans.

In this case, Sierra Club witness Quarles testified, based on his expertise and prior experience with coal waste issues[8] and his analysis of the site conditions, topography, hydrology, and operation of the two impoundments at the Roxboro plant and the one unit at the Mayo plant, that the closure plans proposed by the Company for those units would not meet the requirements of the CCR Rule or of CAMA, and would not protect against future migration of contaminants from the ash into groundwater and, ultimately, surrounding surface waters. (Tr. Vol. 13, pp. 132-73, 175-77.) Witness Quarles' opinion, which was left essentially unrebutted by any Company witness, places in doubt the appropriate treatment of the preparatory and planning expenditures incurred by the Company for which it seeks recovery in this case.

One option would be to allow the Company's current request for cost recovery subject to later adjustment or offset against actual final closure costs as determined in a future general rate case. This option is unsatisfactory since it would involve improper retroactive ratemaking – costs approved for recovery in this case might be disallowed and ordered disgorged in a later case. A second option would be to accept witness Quarles' opinion, which is that the Company is proposing an unworkable and, therefore, unreasonable and imprudent closure plan, and, as a result, disallow the costs in their entirety in this case. I likewise find this option unacceptable since it would preempt a decision that is properly to be made by DEQ and not by the Commission. The sufficiency of the Company's closure plans for these three impoundments is a matter that should first be decided by DEQ, after which the Commission can review the record and make a determination of the reasonableness and prudence of the costs the Company has incurred and will incur. I would therefore conclude that the most appropriate treatment of the costs incurred to date with respect to the three impoundments at the Roxboro and Mayo plants would be to allow the Company to defer those costs to a regulatory asset account for possible later recovery in a future general rate case, after closure plans have

[8] Witness Quarles' testimony is entitled to substantial weight. He was involved in the development of a monitoring program to determine the lateral extent of contamination from the 2008 Kingston, Tennessee ash spill and thereafter has been involved with investigations at more than 70 coal ash disposal sites in the United States. (Tr. Vol. 13, p. 131.)

been approved by DEQ, and upon presentation of a more fully developed record concerning the history of ash management policies and practices at the two plants.

D. H.F. Lee Plant

The Company's H.F. Lee plant in Wayne County was decommissioned in 2012. At that time, there was one active wastewater impoundment at the plant site – the so-called 1982 basin, which was constructed in 1978, containing as of January 1, 2017, an estimated 4.5 million tons of combustion residuals. (Ex. Vol. 16, p. 210.) In addition, there were four inactive or abandoned impoundments as follows: (a) the 1950 basin, last used in 1963; (b) the 1955 basin, last used in 1969; (c) the 1962 basin, last used in 1973; and (d) the so-called "polishing pond," which opened in 1982 and was last used in 2012.[9] Collectively, these four impoundments contained an estimated 1.709 million tons of combustion residuals as of January 1, 2017. (Id.) In this case, the Company seeks to recover $20,759,183 in expenditures made in 2015 and 2016 for preparation of closure plans, engineering for implementation of the plans, and for expenses relating to dewatering the ash in the active impoundment. As far as the record discloses, these costs are not further broken down between the four inactive impoundments and the remaining active 1982 basin.

The inactive impoundments at the Lee plant are, together with those of similar vintage at the Cape Fear plant, the oldest among the Company's total of nineteen impoundments. Three of the four were constructed before the Clean Water Act became effective, and active use of the impoundments ceased before the practice of lined impoundments became widespread. None of the four are subject to the CCR Rule, although their closure is mandated by CAMA. (Id.) The 1950, 1955, and 1962 impoundments were inactive and were no longer in use by the time of the Company's 1987 general rate case. (For shorter reference, I will call these the "pre-1973 impoundments," since they were all inactive by 1973.) The record does not disclose whether any allowance for costs of closure of the pre-1973 impoundments and permanent disposal of the waste ash was made in that rate case.

No party has contested that the items of expenditure or the amounts of the expenditures made by the Company with respect to the impoundments at the Lee plant are reasonable and prudent. The difficulty I find with the Company's request for cost recovery centers on the inactive impoundments, and more particularly on the fact that the pre-1973 impoundments were last used for wastewater treatment and removal of combustion residuals between thirty and thirty-five years before the enactment of CAMA. The impoundments themselves, whose purpose was to treat ash laden wastewater before the treated wastewater could then be discharged into surface waters or recycled for other purposes at the plant, have served no such purpose for the same period of time. The waste products that now must be removed from the footprint of the impoundments and

[9] The exact status and history of the "polishing pond" is not detailed in the record. It is estimated to contain only approximately 9,000 tons of wastes and, therefore, does not appear to materially affect the Company's total expenditures.

permanently disposed are the residuals from coal burned to generate electricity for a very different group of customers than the Company's current ratepayers.

Based on these factors, I find the principle supporting the Court's decision in State ex rel. Utils. Comm'n v. Edmisten, 291 N.C. 451, 232 S.E.2d 184 (1977), to be an apt one for this case – that the costs of service should be borne by those who were customers during the period the service was rendered. Id., 291 N.C. at 470-71, 232 S.E.2d at 195. The facts in Edmisten differ from those in this case in several respects, and Edmisten presents a simpler illustration of the general principle stated. The question that I believe implicates Edmisten in this case can be formulated in the following way. Permanent disposal of waste products from the generation of electricity is an expense directly associated with the generation of that electricity and should, therefore, be treated as an ordinary expense of operation. However, perfect identity between the time period during which electricity is generated and the time the resulting waste products are permanently disposed is not reasonable or even possible. The water used to flush the waste products from the plant must first be treated to remove the combustion wastes, and some accumulation or storage of that waste must occur in order to permit the most efficient and cost-effective permanent disposal of the waste. While an impoundment is still receiving new wastes and is used for treatment of wastewater, removal of accumulated wastes in the impoundment may be impractical and costly. Because some delay between the generation of coal combustion wastes and their final, permanent disposal is not unreasonable, the question then is when does the delay between (a) the production of waste in the course of generating electricity to serve one group of customers and (b) the final disposal of that waste accompanied by a request that then-current customers shoulder the costs of disposal become so great that it offends the principle articulated in Edmisten?

In the case of impoundments that were still actively receiving combustion residuals and treating wastewater when the Lee plant and several others were retired in 2012, it is reasonable for present ratepayers to be assigned costs associated with the final, permanent disposal of the wastes remaining in those impoundments at the time of their decommissioning. However, I would find that this is not so in the case of the pre-1973 impoundments. This distinction in treatment is supported, I believe, by the essentially undisputed evidence in the record as to the manner in which the pre-1973 impoundments were "decommissioned" at the time.

Company witness Kerin testified that when use of the inactive impoundments ceased, no steps were taken to dewater the ash remaining in the impoundments, although over time the impoundments dewatered naturally. (Tr. Vol. 17, pp.116-117.) He also testified that "…at a retired site, the first thing you want to do is start removing the water. That improves the factors of safety of the dam. It also, if you would have seep issues, that will eliminate the seeps." (Tr. Vol. 16, pp. 173-174.) Nor was anything done to protect the ash from rainwater or from storm water runoff from surrounding areas, such as by capping the accumulated ash in place or engineering storm water diversions. None of the ash was excavated and placed in dry stacks, piles, or landfills, and no groundwater monitoring or leachate collection system was installed to detect and prevent migration of contaminants from the ash into groundwater and nearby surface water. (Tr. Vol. 17, pp. 117-118.) Witness Kerin testified that from the time use of the impoundments ceased, no actions were taken other than performing inspections of the dams. (Id. at pp. 118-119.) [10]

In his direct testimony, witness Kerin attempted to avoid the matter of the inactive impoundments by testifying as follows: "In the absence of any regulatory directive to do so, the Company reasonably did not pursue and should not have pursued regulatory closure or retrofitting *for any site that was still generating ash* and that maintained its NPDES permit." (Tr. Vol. 16, p. 115 (emphasis added)) In other words, final disposition of the waste ash accumulated in any impoundment, even an inactive one, could await decommissioning of the generating plant itself. I find this position wholly unpersuasive. It is equivalent to claiming that it would be reasonable and prudent to leave hazardous sludges left from equipment cleaning solvents to be stored in leaking metal containers on an open and unprotected part of the power plant site for as many decades as the plant thereafter continued in operation, without any regard to what might become of them in the meantime.

In short, the pre-1973 impoundments at the H.F. Lee plant were not so much "closed" as they were abandoned, along with the combustion residuals left in them.[11] I would conclude that the Company's failure to take any steps to ensure that the ash in the pre-1973 impoundments remained in place and that contaminants did not enter groundwater or surface water at any time until it was forced to take action by the enactment of CAMA in 2014 was unreasonable and imprudent, and that the extended

[10] Interestingly, when the Lee plant was retired in 2012, the Company commissioned a study of the activities required for decommissioning and the costs associated therewith. This study pre-dated adoption of the CCR Rule and the enactment of CAMA, but was intended to be responsive to the regulatory regime in place at the time under the Clean Water Act and applicable state groundwater protection regulations. For the impoundments at the Lee plant, the study indicated the "[e]xisting ash ponds will be pumped dry, filled with inert debris, capped with 40 mil geo-membrane, geo-net drainage, 18 inches of soil, and vegetated cover." (Ex. Vol. 20, p. 180.) The same activity was indicated for the impoundments at the Cape Fear, Weatherspoon, and L.V. Sutton plants. While there is no evidence to indicate whether CAMA would have addressed the inactive impoundments at the Lee plant differently had they been sooner closed in the manner recommended in the 2012 study, it is reasonable to ask whether the result under CAMA might have been different had the Company taken action to permanently close the impoundments and secure the ash in them within a reasonably prompt period of time after use of the impoundments was discontinued.

[11] The 1988 EPA Report to Congress indicates that as of 1983, North Carolina had in place regulations governing closure of surface impoundments. (p. 4-4) The record in this case does not further detail what those regulations provided. The EPA report does illustrate, generically, two methods of surface impoundment closure – removal of the wastes and dewatering the wastes and covering them with a soil cover. (Tr. Vol. 16, pp. 220-225; Ex. Vol. 21, pp. 513-516.) Whatever the state of the regulations at the time, the undisputed evidence from the Company's own witness is that nothing at all was done when use of the pre-1973 impoundments ceased.

delay in taking any action to dispose of the ash on a permanent basis violates the principle of Edmisten.[12]

The Company has provided no allocation between the pre-1973 impoundments and one active impoundment of any of the costs for which it seeks recovery at the Lee plant; however, witness Kerin testified that although disposal costs of ash wastes are not a direct function of quantities, quantity is certainly a very important determinant of cost. (Tr. Vol. 17, p. 54.) Some costs, such as preparation and submission of a plan for permanent disposal, site mobilization, and similar items, could be considered common to all the different impoundments at a single site, and it seems reasonable to allocate those common costs based on the most important variable involved – the quantity of the wastes in each impoundment. Accordingly, relying on the data provided by the Company in Kerin Direct Exhibit 5 and using the allocation method just described, I would disallow 37.9% of the total for which the Company seeks recovery in this case on account of the impoundments at the H.F. Lee Plant.[13]

E. Cape Fear Plant

The Company's Cape Fear plant near Moncure was decommissioned in 2012, at the same time the H.F. Lee, Weatherspoon, and the coal units at the L.V. Sutton plants also were retired. At that time there was one impoundment constructed in 1985 that was still receiving some waste. The Company estimated that the volume in this 1985 impoundment as of January 1, 2017, was approximately 2.8 million tons. Also at the plant site were four other impoundments whose use had ceased by not later than 1985, as

[12] I do not believe this result is inconsistent with the Commission's 1994 PSNC Order due to significant factual differences between the cases. The manufactured gas plants owned by PSNC were acquired from other owners who had operated them for many years before PSNC purchased them. Three of the six plants were jointly owned with other parties. As far as the 1994 PSNC Order discloses, there was no evidence or finding that when the plants were finally closed in the 1950s, PSNC in any way failed to take steps that were reasonably and prudently known and possible at the time, based on the state of PSNC's knowledge and understanding at that time. I also find it significant that, whereas the Commission found that PSNC had handled by-products from the manufacturing process consistent with applicable laws at the time, in this case the Company's federal criminal admissions, the DEQ administrative and civil actions, and private party civil litigation all relate to actions or omissions under the Clean Water Act, which was in effect at the time two out of the five Lee impoundments were last in use. (Ex. Vol. 16, p. 210.)

[13] Kerin Direct Exhibit 5 reports estimated tonnages of ash as of January 1, 2017, and might be thought more appropriate to base an allocation on the tonnages shown on Public Staff Kerin Cross Exhibit 3, which contains estimates as of August, 2014, when activities commenced to close the impoundments and permanently dispose of the ash wastes. However, the August, 2014 tonnages shown on Public Staff Kerin Cross Exhibit 3 for the closed impoundments are significantly *less* than the estimated tonnages as of January 1, 2017, notwithstanding the fact that the four inactive impoundments had not been receiving any new combustion residuals after August, 2014. (The totals for the one "active" impoundment are the same on both exhibits.) As indicated in the footnotes to the two exhibits, estimated quantities were subject to change based on detailed site examination and analysis. For that reason, I have concluded that Kerin Direct Exhibit 5 provides a more accurate basis for the proposed allocation. (Ex. Vol. 16, p. 210.)

follows: (a) the 1956 impoundment, whose use ceased in 1963; (b) the 1963 impoundment, no longer used after 1978; (c) the 1970 impoundment, discontinued in 1978; and (d) the 1978 impoundment, which no longer received waste after 1985. Taken together, these four discontinued impoundments contained an estimated 2.9 million tons of combustion residuals as of January 1, 2017. None of these impoundments are subject to the CCR Rule, and the Company's expenditures are mandated solely by the requirements of CAMA.

In this proceeding, the Company seeks to recover a total of $16,052,310 in expenditures to cover preparation of closure plans, engineering for implementation, and mobilization and dewatering of the 1985 impoundment. As is the case for the pre-1973 impoundments at the H.V. Lee plant, the four Cape Fear impoundments whose use ceased in or before 1985 (hereafter referred to as "the pre-1985 impoundments") are not subject to the CCR Rule, but are instead subject to closure as mandated by CAMA. The 1985 impoundment, though no longer receiving new wastes after 2012, is classified as "active" under the CCR Rule since it continued to impound water at the time the CCR Rule became effective. Again, as in the case of the impoundments at the H.V. Lee facility, the Company has provided no breakdown of its cost recovery request as between the 1985 impoundment and the pre-1985 impoundments.

The 1978 impoundment was the subject of Count 5 of the federal criminal prosecution, centering on the Company's failure to take timely and reasonable action to maintain and repair the riser and skimmer, allowing leakage in violation of the Company's NPDES permit. The facts are extensively reviewed in the Joint Factual Statement. (Ex. Vol. 21, pp. 142-150.) They demonstrate that the Company was slow to respond or non-responsive entirely to repeated evidence of problems with the riser and skimmer and knowledge that these problems were resulting in leakage from the impoundment. Not until 2013 did the Company begin to dewater the 1978 and 1985 impoundments. This was approximately 28 years after the 1978 impoundment had been retired, a delay that should be considered in light of witness Kerin's testimony, already noted, that the first thing that should be done when an impoundment is retired is to dewater the basin, thereby reducing the hydrostatic pressure that can cause or increase the likelihood of groundwater intrusion or surface seeps.

For the reasons discussed earlier concerning the pre-1973 impoundments at the H.F. Lee plant, I would disallow any cost recovery for removal and final disposal of the coal combustion residuals in the four pre-1985 impoundments at the Cape Fear plant. As was the case with the cost figures for the Lee impoundments, the Company did not provide a breakdown of its total request for cost recovery by individual impoundment. Using the same source of data and the same method of allocating the total costs as in the case of the H.F. Lee plant, I would disallow 50.87% of the total amount of cost for which the Company seeks recovery in this case in account of the impoundments at the Cape Fear Plant.[14]

F. Robinson Plant

The Company's Robinson plant in South Carolina has one impoundment constructed in the mid-1970s. (Ex. Vol. 16, p. 210.) The Robinson plant is now retired and the record is unclear as to the quantity of ash remaining at the plant site. Kerin Direct Exhibit 5 shows an estimate as of January 1, 2017, of approximately 3.2 million tons, while Public Staff Kerin Cross Exhibit 3 indicates that as of September 30, 2014, the quantity of ash in the impoundment was only 660,000 tons, with perhaps additional ash in dry stacks, piles, or otherwise present in some form at the site. This uncertainty is consistent with the general absence of evidence in the record concerning the Robinson plant's history of operations or the management of combustion residuals at the plant site. According to Kerin Direct Exhibit 10, the Company is in this case seeking recovery of $6,415,618 expended to date in preparatory engineering and related expenses for a closure plan to involve excavation of the ash at the site and permanent disposal in a lined landfill. (Ex. Vol. 16, p. 268.) The Company's closure plan has been approved by the South Carolina Department of Health and Environmental Control, a fact which distinguishes the Company's expenses at the Robinson site from the situation with respect to the Mayo and Roxboro plants discussed earlier.

Because none of the intervenors presented evidence disputing the reasonableness or prudence of the Company's expenditures for which it seeks recovery, or concerning the Company's history of management of combustion residuals at the Robinson plant, I would conclude that they should be allowed for recovery in this case, subject to amortization along with other allowed costs for ash remediation and disposal.

G. Weatherspoon Plant

As in the case of the Robinson plant, the parties' evidentiary presentations gave small attention to the Company's Weatherspoon plant, which was retired in 2011 and, at the time of its decommissioning, had one active ash impoundment constructed in 1955 and containing, as of January 1, 2017, combustion residuals estimated at either 2.5 million tons (Ex. Vol. 16, p. 210.), or 1,700,000 tons as of August, 2014. (Ex. Vol. 17, p. 79.) In this case, the Company seeks recovery of $9,120,342 incurred in connection with preliminary preparation of a closure plan and engineering for implementation of the plan involving excavation and offsite disposal of the ash remaining in the decommissioned impoundment. The Company has selected beneficial reuse as its preferred method for permanent disposal of the waste ash from the Weatherspoon impoundment.

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[14] The discrepancies in tonnages between Kerin Direct Ex. 5 and Public Staff Kerin Cross Exhibit 3 that exist in the case of the H.F. Lee plant do not exist in the case of the Cape Fear plant. The small difference in totals likely reflects rounding or different methods of estimation.

The objecting parties presented little or no evidence concerning the reasonableness or prudence of the Company's expenditures for which it seeks recovery in this case, or concerning the Company's history of management of combustion residuals at the Weatherspoon plant. The Weatherspoon plant did not figure in the Company's federal criminal prosecution. Although the 2013 enforcement action commenced in Wake County Superior Court by DEQ contain allegations that the applicable 2L standards for certain groundwater contaminants (iron, thallium, and manganese) were exceeded in or around the Weatherspoon plant at various monitoring sites on various dates, the allegations of DEQ's Complaint are tentative and, in some cases, state that it is uncertain whether these exceedances are naturally occurring or whether corrective action will be required. (Ex. Vol. 22, p. 267.) DEQ's action was resolved by an order on motion for summary judgment, consented to by the Company. (Ex. Vol. 22, pp. 328-407.) Accordingly, I would find that there is insufficient evidence to disallow the costs for which recovery is sought in this case as imprudently incurred and that cost recovery should be allowed.

IV. COAL COMBUSTION WASTE – GENERAL MATTERS, ONCE AGAIN

This proceeding may be the first, but it will not be the last in which recovery of costs for permanent disposal of coal combustion wastes will be at issue. Two questions of moment for future rate cases were litigated in the present case. On one of those questions I am in substantial agreement with the Commission's majority but not so with the other question. Finally, I wish to set out my views about the mismanagement penalty ordered by the Commission majority.

A. Insurance Recoveries

The first matter relates to potential insurance recoveries that may be used to offset some portion of the costs the Company has incurred and will incur for permanent disposal of the waste materials. I concur in the majority's treatment of this issue and wish to set forth my own view as to why that treatment is appropriate. As the evidence disclosed, the Company's entitlement to recover under its insurance policies is currently in litigation that will not be finally resolved for a number of months or even some years. Accordingly, the Company is not presently able to make any useful prediction or estimation of its likely recoveries under the policies in litigation. The Company has proffered that any and all proceeds from the insurance litigation, by judgment or settlement, will be applied, net of costs of litigation, against its costs incurred to comply with CAMA and the CCR Rule. Of course, it is the Company's position that all of those costs are recoverable from ratepayers, now and in the future, including an allowed rate of return. I find this proposal highly unsatisfactory. Under it, the Company would retain full control over the litigation, including the pace of the suit, the costs of the suit, the development of evidence through discovery, the presentation of the case, and the determination whether to settle and, if so, for what amounts. Yet because the Company seeks full recovery from ratepayers today for all of the costs to which insurance coverage is potentially available, it lacks any real incentive to prosecute the pending insurance litigation vigorously, to settle the case for the highest amount that can reasonably be negotiated, or to control the costs of the suit. The Company would retain control but would have no stake in the outcome.

It is, I believe, premature to decide in this case how any insurance recoveries should be allocated between the Company's ratepayers and its shareholders and, in stating this view, I am in accord with the majority. Much depends on how the insurance litigation develops, most particularly on which issues will turn out to be central to the disposition of the litigation and what evidence is developed on those controlling issues. For now, however, I believe that the cost recovery disallowances and cost deferrals that I have advocated in this opinion would give the Company sufficient incentives to ensure that the insurance litigation is prosecuted vigorously and cost effectively. If the Company is able to prevail, either in whole or in part, the Commission will then have an opportunity to assess whether and in what amount the Company should be able to offset the insurance proceeds against items of cost that have been disallowed in rates or deferred for recovery.

B. Ongoing Coal Ash Disposal Costs

The second matter centers on the treatment of the Company's ongoing and future expenditures relating to waste ash disposal. As noted in the beginning, I concur with the majority that these costs are appropriately treated by allowing the Company to establish a regulatory asset account, with the amount of any eventual allowance or disallowance to be determined in one or more future rate cases. I depart from the majority, however, on the extent to which the Company may be allowed to accrue a rate of return on this regulatory asset account.

The expenditures that will be recorded to this account are, in my view and as I have already explained, operating expenses upon which a return is not ordinarily allowed. The Company contends that a rate of return is appropriate nonetheless since the expenses are being capitalized and will be funded from the Company's working capital, citing the decision in State ex rel. Utils. Comm'n v. Virginia Electric & Power Co., 285 N.C. 398, 206 S.E.2d 283 (1974) (VEPCO) for support of its position. The matter is not quite so simple. The Court in VEPCO did not hold that *all* amounts classified as working capital could be included in the utility's rate base upon which it was entitled to earn a return, but only those funds used as working capital that were provided by or belonged to investors. After first endorsing inclusion in rate base of the Company's own funds used as working capital, the Court pointed out:

> Conversely, the utility is not entitled to include in its rate base funds which it has not provided but which it has been permitted to collect from its customers for the purpose of paying expenses at some future time and which it actually uses as working capital in the meantime. Such funds, so supplied by the customers, are 'used and useful in rendering the service' and the utility, having lawfully collected them, is the owner thereof. Nevertheless, such funds, so collected from the customers and used by the

> utility as working capital, are not 'the public utility's property' within the meaning of G.S. 133(b)(1).

VEPCO, 285 N.C. at 415, 206 S.E.2d at 293. Importantly, the Court also observed that the determination as to when working capital is sufficient such that no additional amount is required to be included in rates is largely a subjective one. Id.

The record in the present case is unclear as to the extent to which the Company will require an increase in investor-provided working capital beyond what is currently available to fund ongoing expenditures for coal ash disposal. The Company has been able to fund from the revenues provided by existing rates and from existing working capital its coal ash expenditures in 2015 and 2016, and these amounts will be replenished as allowed by the Commission's order allowing amortization and recovery in rates of these expenditures. Although the Company contends that in some future years its expenditures for coal ash disposal will exceed its expenditures in the test year, it also acknowledges that in other years its expenditures are projected to be less. (Tr. Vol. 6, pp. 144-145.) In its application, the Company proposed to increase its pro forma cash working capital by $129.1 million on account of future expenditures for coal ash disposal costs, and to recover this amount from customers in rates. (Tr. Vol. 6, pp. 41-42.) This amount represented the Company's expenditures in the test year, which, as I noted already, it has funded from its existing working capital under current rates. I would infer from this requested number that the Company does not believe that it needs an increase in working capital for those years in which its future expenditures are projected to exceed the test year amount.

Because I am unable to determine from the record as it stands what portion, if any, of the Company's future coal ash disposal expenditures may require an increase in investor-provided working capital, I am therefore unable to support the accrual of a rate of return on amounts recorded to the regulatory asset account for future coal ash disposal costs.

C. The Penalty for Mismanagement

Finally, I write to explain my reasons for not joining the majority's decision to impose what it has called a penalty for mismanagement. The majority would allow all costs sought for recovery by the Company for the period January 1, 2015, through August 31, 2017, excepting only the $9.5 million excess disposal costs at the Asheville Plant. Its proposed penalty consists of amortizing recovery of the allowed costs over a five year period and including a return on the unamortized balance equal to the authorized combined return on rate base but then reduced by the sum of $6 million per year. The majority estimates that the value of this penalty is approximately $30 million. I cannot concur that what the majority has ordered constitutes, in any real sense, a penalty.

Requiring amortization over a period of years for extraordinary operating expenses is not unusual, and the five year period allowed by the majority for recovery of costs already incurred is what the Company has requested. I do not consider allowing a return on the unamortized balance, albeit at a reduced rate, to be a penalty in any meaningful sense. In Thornburg I, the Supreme Court upheld the Commission's allowance and amortization of certain costs associated with a cancelled generating plant as "reasonable operating expenses," while denying any return on the unamortized balance of such expenses. In the course of its discussion of the issue, the Court observed:

> While this statute [referring to G.S. 62-133(b)] makes clear that the rates to be charged by the public utility allow a return on the cost of the utility's property which is used and useful within the meaning of N.C. Gen. Stat. § 62-133(b)(1), the statute permits recovery but no return on the reasonable operating expenses ascertained pursuant to subdivision (3).

Id., 325 N.C. at 475, 385 S.E.2d at 458. Elaborating on this point later in the same opinion, the Court stated:

> We note that jurisdictions have generally dealt with the allocation of cancelled plant costs in one of the following three ways: (1) recovery of all of the costs from ratepayers, by allowing amortization of the investment plus a return on the unamortized balance; (2) recovery of all costs from shareholders through a total disallowance of recovery in rates, instead requiring the utility to write off the entire amount in a single year; or (2) recovery from ratepayers and shareholders through amortization of costs in rates over a period of years, with no return on the unamortized balance. Strong policy considerations support the Commission and commentators who have concluded that method three is the best of the three alternatives in that it promotes "an equitable sharing of the loss between ratepayers and the utility stockholders."

Id., 325 N.C. at 480, 385 S.E.2d at 460 (citations omitted).

The Thornburg I decision involved investment in cancelled plant, but the Commission applied the same method of recovery to costs associated with environmental remediation costs arising from decommissioned manufactured gas plants in the 1994 PSNC Order, where deferral and amortization was permitted without any rate of return on the unamortized balance, even though the Commission did not in its opinion make a finding of imprudence or mismanagement.[15] Finally, in the present case itself, the Commission majority would permit the Company to recover certain extraordinary operating costs incurred in connection with a series of major storms but proposes not to

[15] As noted in the passage quoted from Thornburg I, other states have taken different approaches, and that was also true in the series of decisions from the 1990s relating to manufactured gas plants. However, the Commission's decision not to allow a return on unamortized balances in the 1994 PSNC Order was not unique. Similar decisions were made in some, but not all, other jurisdictions. E.g., Northern States Power Company, Docket No. G-002/GR-86-160, 1987 Minn. PUC Lexis (Minn. Pub. Util. Comm'n, Jan. 27, 1987); Chesapeake Utilities Corp., Docket No. 85-17, 1986 Del. PSC Lexis (Del. Pub. Serv. Comm'n. March 25, 1986).

allow any return on the unamortized balance of those costs. Again, disallowance of a return is not being justified by any finding that the Company had mismanaged its response to the storms. Because I consider the costs of permanent disposal of coal ash wastes to be an operating expense under G.S. §62-133(b)(3) I find these precedents particularly compelling.

Two additional considerations lead me to the view that the imposition of a mismanagement penalty in the amount established by the majority is not an adequate response to the evidence in this case. In earlier cases in which the Commission has determined that imposition of a penalty for mismanagement and poor service was appropriate, the Commission has often endeavored to identify the specific ways in which the utility has fallen short and, where possible, to quantify the financial consequences of the mismanagement or poor service. This has been done to ensure that the amount of the penalty is not disproportionate to the nature of the underlying acts or omissions at issue. In the present case, I am not able to make any clear connection between the amount selected for the penalty ($6 million a year for five years) and any particular actions or omissions by the Company. In part for this reason, I prefer an approach that attempts to explore and then quantify causal relationships between specific acts of mismanagement and imprudence, and the resulting financial loss or avoidable costs.

Third, and finally, I note that in past cases where the Commission has seen fit to impose a penalty for mismanagement, there has been a forward-looking element to the Commission's action; that is, the penalty was not merely a response to the utility's past actions, but was also designed to provide an incentive for the utility to correct errors and improve future service. In the present case the imposition of a generic penalty may do little to provide any additional incentive for better service by the Company in the future. As a result of the federal criminal plea agreement and the conditions of probation arising therefrom, the adoption of the CCR Rule, the enactment and implementation of CAMA, and the terms of the various settlement agreements embodied in judgments entered in DEQ administrative proceedings and private party lawsuits, the Company is now subject to a highly prescriptive and closely-monitored regime dictating the details of how it will manage coal ash wastes from this point forward. In addition, and unlike those instances where the Commission has imposed a penalty for poor service or mismanagement, the Company has been subjected to steep and punitive criminal fines, civil penalties, and costly administrative settlements all occasioned by its past actions.[16]

For all these reasons, I am unable to join the majority's imposition of what it calls a penalty for mismanagement. I would instead, and for the reasons previously set forth, disallow from cost recovery and exclude from rates the following amounts:

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[16] Although I am being repetitive in doing so, I believe it is important to state once again that the Company is not seeking in this case any recovery on account of any criminal or civil fines, penalties or forfeitures, nor is it permitted to do so. This is a point that has often been overlooked by opponents of the Company's proposal for cost recovery.

1. **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]** in preparation, transport, and offsite disposal costs incurred to remove wastes from the two impoundments at the L.V. Sutton plant for disposal at the Brickhaven site in Chatham County.

2. $6,693,390 in accelerated groundwater remediation costs incurred at the L.V. Sutton plant pursuant to the September 29, 2015, agreement with the North Carolina Department of Environmental Quality.

3. $9,500,000 in excess contractual costs for offsite disposal of wastes from the Asheville plant.

4. All costs with respect to the permanent disposal of ash wastes from the three pre-1973 impoundments at the H.V. Lee Plant, which based on the evidence provided, I would determine to be $7,867,730 on a system-wide basis through December 31, 2016. This number would be adjusted to calculate the North Carolina retail allocation. The disallowance would extend to all costs from before and after January 1, 2017, related to the pre-1973 impoundments.

5. All costs with respect to the permanent disposal of ash waste from the four pre-1985 impoundments at the Cape Fear Plant, which in this case and based on the evidence provided, I would determine to be $8,265,810 on a system-wide basis through December 31, 2016. This number would be adjusted to calculate the North Carolina retail allocation. The disallowance would extend to all costs from before and after January 1, 2017, related to the pre-1985 impoundments.

6. Defer to a regulatory asset account all costs sought in this case, totaling $35,237,688, for the three impoundments at the Mayo and Roxboro plants, for further determination at the Company's next general rate case, and after DEQ determination as to the sufficiency and adequacy of the closure plans submitted by the Company.

For all remaining costs incurred for the period January 1, 2015, through October 31, 2017, I would permit deferral and amortization over a period of five years, the period requested by the Company, but with no return allowed on the unamortized balance, in accord with prior Commission policy and practice and not as a penalty. Finally, I would grant deferral accounting treatment for all future costs, except for those items disallowed as noted above, but the deferral account would not accrue a rate of return.

/s/ Daniel G. Clodfelter

Commissioner Daniel G. Clodfelter