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

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

PROPOSED ORDER OF THE PUBLIC STAFF

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, 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
Corporation

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

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

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

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

For the 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 the North Carolina Sustainable Energy Association (NCSEA):
Peter H. Ledford, General Counsel
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

For the Fayetteville Public Works Commission (Fayetteville PWC):

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

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

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

For the 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)[1]; Stephen G. De May, Senior Vice President of Tax and Treasurer, Duke Energy Business Services, LLC (DEBS)[2]; David L. Doss, Jr., Director of Electric Utilities and Infrastructure Accounting, DEBS; Christopher M. Fallon, Vice President of Duke Energy Renewables and Commercial Portfolio, Duke Energy; 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

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

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

Combustion Products, DEBS; 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, the 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, the NC Justice Center et al. 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 et al. 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.[3] 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 Attorney General's intervention 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 this docket with Docket No. E-2, Sub 1131 (DEP's request to defer incremental storm 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 Docket No. E-2, Sub 1142. On August 29, 2017, the Commission issued an order

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

consolidating the general rate proceeding with DEP's request to implement a job retention rider in Docket No. E-2, Sub 1153.

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 II 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 et al. 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 the 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 et al. to extend to October 23, 2017, the deadline to file the direct testimony of witness, John Howat. On October 23, 2017, NC Justice Center et al. 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 Attorney General 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 filed 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 accept his pre-filed testimony.

On November 16, 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 hearing scheduled to begin Monday, November 20, 2017 to Monday, November 27, 2017 at 1:30 p.m.

On the same day, the Commission issued an Order granting NCLM's motion to excuse witness Bill 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 the parties in this docket, with the exception of: (1) cost recovery of DEP's coal ash costs, recovery amortization period and return during the amortization period, allocation issues associated with coal ash costs, ongoing costs to be included in rates, and whether certain coal ash 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 the Commercial Group filed a Settlement Agreement resolving all issues among them regarding this docket. On the same day, DEP and Kroger filed a Settlement Agreement resolving all issues among them regarding 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 day, 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: Emily Zucchino, Cary Rodgers, John Merrell, Tom Clark, Lois A. Jones, Keely Wood, Debbie Hall, Tavares Bostic, Kim McCall, Karen Tucker, Kent McGill, and Margaret Wolfe Roberts

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, and Allison Keenan

Asheville: Bill Whalen, Dave Hollister, Dan Gilbert, Cathi Culver, Judy Mattox, Kelly Williams, Stephanie Biziewski, Brad Rouse, Xavier Boatwright on behalf of Jeri Cruz-Segarra, Ken Brame, Hartwell Carson, Kendall Hale, Marston Blow, Samantha Wilds, Cathy Scott, Judith Kaufman, Steve Carter, Cathy Holt, Jim McGlinn, James Smith, Michael Kohnle, Jamie Friedrich, 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 Boatwright, Patrick Taylor, and 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, 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, Sara Mullens, Anne Harrington, and 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 Zofziger, Patricia Leonard, Kevin Blackburn, Caylan McKay, Linda Susan Porter, Connette Bradley, Roberta Buckles, Elizabeth Murray, Esther Murphy, Isabelle Sheppard, Bill Garrity, Paul Greiner, and Pauline Richardson

This matter came on for evidentiary 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. The Sierra Club presented the testimony of witness Quarles. NC Justice Center et al. 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. The pre-filed testimony of these witnesses was copied into the record as if given orally from the stand and their exhibits entered into evidence. 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 et al. witness Howat; the testimony 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 the Late-Filed Exhibit 1 of witness Floyd in response to the Commission's request during the evidentiary hearing. On the same day, DEP filed Late-Filed Exhibits 1 - 5 in response to Commission questions or requests made during the evidentiary hearing.

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

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 AND CONCLUSIONS

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 this 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, 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.

<u>The Application</u>

5. DEP, by its Application and initial direct testimony and exhibits, 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 (ROE) of 10.75%. On September 15, 2017, DEP filed

supplemental testimony and exhibits that detailed a $57.958 reduction in its original request, thereby reducing the total Company proposed increase to approximately $419.5 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 (the 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 the Commercial Group that are consistent with the language of the Stipulation.

8. The Commission, having carefully reviewed the Stipulation and all of the evidence of record, finds and concludes that the Stipulation is the product of the "give-and-take" in settlement negotiations between the Stipulating Parties, is material evidence, and is entitled to be given appropriate weight in this proceeding, along with other evidence from the Company and intervenor parties, statements from customers of the Company, and testimony of public witnesses concerning the Company's Application.

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 coal ash costs, the recovery amortization period and return during the amortization period, allocation issues associated with coal ash costs, the amount of ongoing coal ash costs to be included in rates, or whether certain coal ash 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; and while they 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.

10. Settlement Exhibit 1 was attached to the Stipulation, showing the monetary significance of each of the settled or unresolved issues. Subsequently, a corrected and updated version of the exhibit, marked as Peedin Exhibit 1 Second Revised, was admitted in evidence at the hearing and acknowledged by the Stipulating Parties to be a correct statement of the effect of each adjustment on the Company's proposed annual rates. Peedin Exhibit 1 Second Revised specified the amount of the annual rate increase that would result if all the unresolved issues were decided by the Commission in DEP's favor, as well as the amount of the increase that would result if all

these issues were resolved in favor of the Public Staff. The Stipulating Parties further agreed that the amounts shown on Peedin Exhibit 1 Second Revised "will be impacted by the Commission's decision on the Unresolved Issues which will impact gross revenues, revenue deductions and rate base".

11. The accounting adjustments agreed to by DEP and the Public Staff are set out in detail in the Stipulation and in Peedin Exhibit 1 Second Revised, Schedule 1. The Stipulating Parties agree that the settlement on those issues will not be used as a rationale for future arguments on contested issues brought before the Commission. The Commission finds and concludes that for the present case, the accounting adjustments outlined in the Stipulation are just and reasonable to all parties in light of all the evidence presented.

12. The Stipulating Parties reached other agreements that do not directly impact the amount of the rate increase approved in this Order. These agreements are set forth in Section IV of the Stipulation, are binding on the Stipulating Parties, and are just and reasonable to all parties in light of all the evidence presented.

13. Among the accounting adjustments agreed to by the Stipulating Parties is one that provides that the excess deferred income taxes (EDIT) the Company collected pursuant to the Commission's May 13, 2014 order in Docket No. M-100, Sub 138, should be returned to customers through a levelized rider that will expire at the end of a four-year period. This provision of the Stipulation will result in a $42.577 million annual

reduction in rates for the four years following the effective date of the rates approved herein.

14. 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 Commission finds and concludes that the Stipulation is material evidence entitled to appropriate weight in determining DEP's overall rate of return, cost of debt, return on equity and capital structure.

15. Based on the expert witness evidence, the public witness evidence and the Stipulation, the Commission finds 9.9% to be a reasonable rate of return on equity for DEP in this general rate case.

16. Based on the expert witness evidence, the public witness evidence and the Stipulation, the Commission finds 52% equity and 48% debt to be a reasonable capital structure for DEP in this case.

17. Based on the expert witness evidence, the public witness evidence and the Stipulation, the Commission finds 4.05% to be a reasonable cost of debt for the purposes of this case.

18. The rate increase approved in this case, which includes the approved 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. 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.

19. The 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.

20. The 9.9% 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.

21. 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.

22. 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 increment rider, as set forth in the Stipulation, is just and reasonable to all parties in light of all the evidence presented.

23. Paragraph IV.I. of the Stipulation provides that the overall quality of electric service provided by the Company is adequate. The Commission finds this provision of the Stipulation to be just and reasonable.

24. 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. The Commission finds this provision of the Stipulation to be just and reasonable.

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

26. The Stipulation provides for use of the Summer Coincident Peak (SCP) methodology for cost allocation between jurisdictions and among customer classes in this case. The Commission finds and concludes that 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, and that 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. The Company shall file annual cost of service studies based on both the SCP and summer/winter coincident peak and average (SWPA) methodologies.

27. 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 reasonable, appropriate, and nondiscriminatory. 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. As provided in Paragraph IV.F. of the Stipulation, the Company may increase the Basic Customer Charge (BCC) for the following schedules as follows: Schedule RES up to $14.00 per month and R-TOUD and R-TOU up to $16.85 per month.

28. In conjunction with the Commission's decisions set out below on the contested issues, the Stipulation will provide the Company with an increase in its annual North Carolina retail rates of $99.726 million for the first four years the rates approved

herein are in effect, and $142.303 million thereafter. The Commission finds and concludes that based on all of the evidence, these rates will be just and reasonable, and that 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.

29. After giving effect to the approved increase, the annual revenue requirement for DEP is $142,303,000, exclusive of the impact of the EDIT Rider, which 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.

Coal Ash

30. DEP should maximize utilization of on-site disposal options to the greatest extent possible where technically feasible and allowable under state and federal regulations.

31. Prior to making a determination to move coal ash off-site, it is appropriate for DEP to evaluate the technical feasibility of on-site management options.

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

33. DEP had sufficient information to conclude that a greenfield landfill capable of handling the coal ash on-site at the Sutton facility could have been

reasonably built and operated to comply with the closure deadlines in Section 3.(b) of S.L. 2014-122.

34. The decision to transport ash from Sutton to the Brickhaven structural fill facility, as opposed to managing all of the coal ash on-site at Sutton, was not reasonable or prudent.

35. The secondary containment system at the Sutton on-site landfill was not necessary for compliance with state solid waste landfill regulations.

36. The need to excavate and stack coal ash from the 1982 basin into the 1964 basin at the Asheville facility was avoidable.

37. DEP's management of ash removal from the 1982 basin at Asheville in 2015 and 2016 was imprudent.

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

39. The transportation costs incurred by DEP for the transportation of ash material from the Asheville facility to the DEC Cliffside landfill are excessive and should instead be comparable to the transportation costs on a per-mile basis associated with the transportation cists included in other contracts entered into by DEP.

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

41. In Docket Nos. E-2, Sub 1103, and E-7, Sub 1110, DEP and DEC jointly filed a request that the Commission issue an order authorizing them to defer in a regulatory asset account certain costs incurred in connection with compliance with federal and state environmental requirements regarding CCRs. By order dated July 10, 2017, the Commission consolidated the DEP request with the present general rate case. DEP and the Public Staff supported the deferral in their Docket No. E-2, Sub 1142, rate case testimony. The Commission finds that the deferral request is reasonable and appropriate.

42. It is reasonable and appropriate to add a return accumulated on the principal amount of deferred coal ash expenditures through January 2018, and to use a mid-month cash flow convention for calculation of that return.

43. In the test period, DEP incurred $88,000 in identified litigation costs for cases involving environmental violations. DEP also incurred approximately $6.7 million for extraction wells and treatment of contaminated groundwater. It would be unreasonable to include either of these costs in rates.

44. DEP incurred approximately $60.1 million of costs related to CCRs from January 1, 2015, to August 31, 2017. Deferral of these costs is appropriate, and it is just and reasonable for the Company to recover these costs in rates over a 26-year amortization period, with no return on the unamortized balance.

45. DEP expects to incur substantial costs related to coal ash in future years. It is just and reasonable to allow deferral of those costs, with a return at the authorized weighted cost of capital during the deferral period. Ratemaking treatment of such costs will be addressed in future rate cases.

46. DEP has not presented credible and persuasive evidence that a decision by the Commission adopting the Public Staff's recommendation for equitable sharing of coal ash costs would be detrimental to DEP's credit rating or credit metrics.

47. DEP, with a Moody's secured debt rating of Aa3, on September 16, 2016, issued 30-year First Mortgage Bonds Taxable at the interest rate of 3.70%, and on September 8, 2017, issued 30-year First Mortgage Bonds Taxable at the interest rate of 3.60%. The 3.60% interest rate is the lowest rate ever on a DEP 30-year First Mortgage Bonds Taxable. DEP was not collecting coal ash remediation cost revenues from customers on either of those dates.

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

49. It is reasonable and appropriate to allocate all coal ash expenditures by the energy allocation factor, rather than the demand-related production plant allocation factor.

Coal Ash Sales

50. 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, G.S. 62-133.2 et. seq.

51. The beneficial reuse of coal ash, 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).

52. 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).

Storm Costs

53. The North Carolina retail normalized annual level of storm costs to be included in the Company's rates in this case is $11.018 million. However, the Company is not entitled in the future to defer, and recover through amortization, all storm costs incurred in excess of $11.018 million in a given year. The amount to be deferred and recovered through amortization is determined by deducting the normal level of costs

(i.e., costs within the normal range of variation) from total storm costs incurred in a given year.

54. The Company should be authorized to defer and amortize $52.752 million of the $80.152 million in North Carolina retail storm costs it incurred in the test year. The remaining $27.4 million is within the normal range of variation of storm costs experienced by the Company in recent years. The $52.752 million deferral should be amortized over a period of 10 years, beginning in October 2016.

55. The Company should not be authorized 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.

JRR

56. 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.

57. 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. The JRR proposed by the Company, as modified by the Stipulation and the prior Finding of Fact, is not unduly discriminatory and is in the public interest.

58. Ratepayers, the Company, and its shareholders all benefit from the retention of North Carolina jobs and the load related to those jobs. The Company's recovery of the JRR revenue credits should be reduced by $3.5 million each year the JRR is in effect, to recognize the benefit to shareholders of the JRR.

EVIDENCE IN SUPPORT OF FINDING OF FACTS AND CONCLUSIONS NOS. 1-4

The evidence supporting these findings 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 IN SUPPORT OF FINDINGS OF FACTS AND CONCLUSIONS NOS. 5-6

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.

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. The Stipulation is based upon the same test period.

EVIDENCE IN SUPPORT OF FINDINGS OF FACT AND CONCLUSIONS NOS. 7-13

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.

The Stipulation resolved many, but not all, of the issues in dispute between the parties. The issues that were not stipulated included: (1) coal ash issues, such as how much of its coal ash costs DEC should be allowed to recover, the length of the amortization period for any recovery, the return to be allowed during the amortization period, allocation issues associated with coal ash costs, the amount of ongoing coal ash costs to be included in rates, and whether certain coal ash costs are recoverable under G.S. 62-133.2; (2) storm cost issues, including the amount of the Company's requested deferred storm costs to be recovered, the amortization period of any such recovery, and the amount of the adjustment to normalize storm expenses on an ongoing basis; and (3) issues relating to the Company’s proposed JRR, including whether companies involved in the transportation or preservation of a raw material or a finished product (e.g., pipeline customers) should qualify for the rider, and whether and how the rider should be funded after the expiration of the agreed-upon contribution of $3.5 million from DEP's shareholders for the initial year. These unresolved issues were left for resolution by the Commission.

DEP witnesses Fountain, Bateman, Hevert, De May, and Wheeler testified in support of the partial settlement. Witness Fountain testified that the parties had reached agreement on 20 separate issues. Among other matters, the parties agreed on (1) a return on equity of 9.9 percent, a return on debt of 4.05 percent, and a capital structure of 52 percent equity and 48 percent debt; (2) amortization of the costs of the Harris Combined Construction and Operating License Application (COLA) over an eight-year period; (3) the establishment of a regulatory asset to defer and amortize expenses associated with the Company's Customer Connect project; (4) disallowance of certain costs related to the Mayo Zero Liquid Discharge and Sutton combustion turbine projects; 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; and (5) setting the BCC for Schedule RES at $14.00 per month and Schedules R-TOUD and R-TOU at $16.85 per month. Witness De May testified that the Stipulation will support the Company's ability to achieve its financial objectives. Witness Hevert stated that the stipulated 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 these items. Witness Maness testified on the impact of the partial settlement on the unresolved coal ash issues, and witness Parcell stated that the settlement reflects the result of good faith, "give-and-take", and compromise-related negotiations among the parties.

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 <u>State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc</u>., 348 N.C. 452, 500 S.E.2d 693 (1998) (<u>CUCA I</u>), and <u>State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc.</u>, 351 N.C. 223, 524 S.E.2d 10 (2000) (<u>CUCA II</u>). In <u>CUCA I</u>, 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. 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court said 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 (emphasis added).

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 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 Stipulation is material evidence to be given appropriate weight in this proceeding.

EVIDENCE IN SUPPORT OF FINDINGS OF FACT AND CONCLUSIONS NOS. 14-20

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.

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 settlement 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 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 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). 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, Attorney General witness Polich, CIGFUR II witness Phillips, and CUCA witness O'Donnell. No 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 return on equity for a public utility. Cooper, 366

N.C. 484, 739 S.E.2d at 548. This is a requirement announced by the Supreme Court in its Cooper decision.

The Commission had occasion to apply both prongs of the Cooper decision in connection with its Order Granting General Rate Increase, issued May 30, 2013, in Duke Energy Progress' last rate case in Docket No. E-2, Sub 1023 (DEP Sub 1023 Rate Order), and does so again in this case. However, 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 return on equity, as interpreted by the Supreme Court in Cooper, 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 DEP Sub 1023 Rate Order, constitutional constraints upon the Commission's return on equity decision, established by the United States Supreme Court decisions in Bluefield Waterworks & Improvement Co., v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) (Bluefield), and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) (Hope):

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

DEP Sub 1023 Rate Order, at 29.

Second, the rate of return on equity is, in fact, a cost. The return 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 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." 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 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 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." (DEP Sub 1023 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 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 return on equity expert witnesses' analyses. The Commission noted this in the DEP Sub 1023 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." DEP Sub 1023 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 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 DEP Sub 1023 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.)

DEP Sub 1023 Rate Order, p. 35-36.

Thus, the Commission must exercise its subjective judgment so as to balance two competing 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.

It is against this back drop 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. <u>Evidence from expert witnesses on cost of equity capital</u>

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 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% with the average of the three means of 8.92%.

He testified with regard to his constant growth DCF that regardless of the method employed, an authorized ROE 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.

Mr. 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. Mr. 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. Mr. Hevert used the beta coefficients reported by Bloomberg and Value Line. He testified that his CAPM analysis suggested an ROE 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 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 ROE 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 ROE, 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. Mr. Hevert testified that based upon the regression coefficients, the implied ROE 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 David Parcell performed three ROE 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:

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

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

3. Years 2017, 2018, and 2020-2022 projections of earnings retention growth (per Value Line);

4. Years 2014-2016 to 2020-2022 projections of EPS, DPS, and BVPS (per Value Line); and,

5. 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 ROE 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 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 perform 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 U.S. 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 U.S. 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 cost of equity of 6.1% to 6.7% for the Parcell and Hevert proxy groups.

However, Mr. 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 U.S. 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, 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 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:

1. The return to the equity owners be sufficient 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;

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 returns on equity (ROE's) 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. Mr. Parcell used the experienced ROE's 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 ROE's 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 ROE's 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 ROE's and market to book ratios of his proxy group, which all range over $20 billion in market value exceed those of Mr. Hevert's proxy group, which are not selected based upon size.

Mr. 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 ROE's 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 ROE's 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 Mr. Parcell's direct testimony Exhibit DCP – 1, Schedule 12. Mr. Parcell testified that based upon recent and prospective ROEs and market to book analyses, his comparable earnings analysis indicates that the ROE 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, commission staff, 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 ROE 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, ROE 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 positons. 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 ROE component of the Stipulation, witness Parcell testified that DEP requested a ROE of 10.75%, which Mr. Parcell stated in his direct testimony was well above industry norms in recent years. He proposed a 9.2% ROE (i.e., approximate mid-point of a ROE 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 while he continues to believe his specific 9.2% ROE recommendation is appropriate at this time, he testified that the upper end of his comparable earnings range of 9.0% to 10.0% contains the 9.9% Stipulation ROE level. He also stated that a 9.9% ROE is 0.70% above his 9.2% recommendation and is 0.85% below DEP’s 10.75 ROE request. As a result, the 9.9% ROE in the Stipulation is a “compromise” between DEP’s and the Public Staff’s respective proposals. The 9.9% ROE 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 his comparable earnings analyses considers the recent historic and prospective ROE's for the groups of proxy utilities companies utilized by himself and DEP witness Hevert. He testified his conclusion of 9.0% to 10.0% reflects the actual ROE's of the proxy companies, as well as the market-to-book ratios of these companies. Mr. Parcell further testified that in the recent Dominion North Carolina Power ("DNCP") rate proceeding, Docket No. E-22, Sub 532, Order dated December 22, 2016, the 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 ROE of 9.9% (versus the 10.5% requested). The Commission approved the cost of capital components of that proposed settlement. Witness Parcell testified the equity ratio and ROE in the proposed Stipulation in this current DEP proceeding are consistent with those of the DNCP proceeding.

DEP witness Hevert testified in support of the Stipulation on the agreed-upon ROE, capital structure, and overall rate of return contained in the Stipulation. Mr. Hevert testified although the Stipulated ROE 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 the Company has determined that the terms of the Stipulation, in particular the stipulated

ROE and equity ratio, would be viewed by the rating agencies as constructive and equitable, and that he understands and respects that determination.

Mr. Hevert testified although the stipulated ROE 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. Mr. 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 ROE is a reasonable resolution of an otherwise contentious issue.

Mr. Hevert testified that he considered the stipulated ROE in the context of authorized returns for other vertically integrated electric utilities. He testified that from January 2014 through November 2017, the average authorized ROE for vertically integrated electric utilities was 9.85%, only five basis points from the Stipulated ROE. 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 ROE's for electric utilities are viewed as having constructive regulatory environments. Mr. 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.[4]

Within RRA’s ranking system, North Carolina is rated “Average/1”, which Mr. Hevert testified falls in the top one-third of the 53 regulatory commissions ranked by RRA. Witness Hevert testified that the stipulated ROE falls 13 to 14 basis points below the mean and median authorized ROE, 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 ROE is a reasonable, if not somewhat conservative measure of DEP’s cost of equity.

Mr. 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

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

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.

Attorney General 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 ROE of 10.2%. He testified market data indicates a substantially lower ROE 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 ROE 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 ROE recommendations.

Mr. 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, 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 ROE of 8.48%. He testified he used the same proxy group as Mr. Hevert.

Mr. Polich testified one of the reasons his analysis is so different than Mr. Hevert's multi-stage DCF is because Mr. 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 Energy

Information Administration 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 Mr. Hevert's figure. Mr. Polich testified Mr. Hevert's reliance on the exaggerated five-year growth rate significantly inflates his growth estimate and ROE calculations and does not reasonably reflect the need to use a longer-term growth rate in the two-step DCF model. Witness Polich testified 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 .708 and median of .675. His CAPM ROE analysis results were low mean ROE of 7.22%, weighted median ROE of 7.56%, and high mean ROE of 8.68%.

CUCA witness O'Donnell testified that the most useful methodology to produce realistic ROE 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 ROE 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. Mr. 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 ROE based upon his comparable earnings analysis was the range of 8.75 to 9.75%.

Witness O'Donnell testified for his CAPM, he used for the risk-free rate and the current 30-year US 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 .72 and the beta for Duke Energy Corporation was .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 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 ROEs authorized by commissions to investor-owned utilities in 2014, 2016, 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 ROE for vertically integrated utilities authorized from 2014 through present is 9.79%. They further testified that there is a continuing declining trend in authorized ROE's for vertically integrated utilities over this time period. The average ROE authorized for vertically integrated utilities in 2014 was 9.92%, in 2015 is was 9.75%, in 2016 is was 9.77%, and so far in 2017 it is 9.70%.

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

CIGFUR II witness Phillips did not perform cost of capital analyses. He testified DEP's ROE of 10.75% is excessive and should be rejected. He stated that DEP's current authorized ROE is 10.2%, which was authorized in the Commission's Final Order in Docket No. E-2, Sub 1023, issued on May 30, 2013. Mr. 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 ROE's resulting from utility rate cases. The most recent report, updated through June 30, 2017, shows that the national average authorized ROE for electric utilities in the first six months of this year is 9.61%, nearly 60 basis points below DEP's currently authorized ROE. Witness Phillips concluded that DEP's current approved ROE, and definitely its requested ROE, are significantly above the current market cost of equity. He recommended that the Commission authorize a ROE 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 recently concluded 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, 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 decision, as well as the DEP Sub 1023 Rate Case. In both of those cases return on equity expert testimony from CUCA witness Kevin O'Donnell provided an alternate 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 faulted the Commission for not making explicit its evaluation of this testimony, and thus the Commission in the DEP Sub 1023 Rate Order in fact made an express evaluation of witness O'Donnell's testimony in accordance with the Cooper 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%, and witness Hevert noted that the median authorized rate of return on equity for vertically integrated utilities included in Commercial Group Exhibit CR-3 was 9.65%. In addition, as witness Hevert noted, North Carolina is generally viewed by the credit ratings agencies to be a credit supportive jurisdiction, and a rate of return on equity of 9.9% is consistent with the mean and median returns recently awarded to utilities in jurisdictions that are considered to be credit supportive. 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 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 return on equity and is 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. Utilities Commission 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.

In contrast, 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 percent and 11.30 percent, 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 percent). 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 percent 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 has 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 have experienced significant economic improvement during the last several years. He testified that 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 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 DEP provides service in 51 counties, and 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, 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 by non-expert witnesses with respect to the impact of changing economic conditions on DEP's customers. In that regard, the Commission held five evening hearings throughout the Company's North Carolina service territory to receive public testimony. The Commission accepts as credible, probative and entitled to substantial weight the testimony of public witnesses, illustrating how numerous North Carolina citizens struggle to make ends meet under current economic conditions. The Commission also accepts as credible, probative and entitled to substantial weight the testimony of witnesses Hevert and Parcell indicating that economic conditions in North Carolina are highly correlated with national conditions, and that such conditions are reflected in his econometric analyses and resulting rate of return on equity recommendations.

c. Commission's Decision Setting Rate of Return and Approving Rate 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.[5] A component of cost of service as important as return on investment is test year revenues.[6] 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

---

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

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

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 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 ratebase 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.

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 credit worthiness 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 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, Attorney General witness Polich, CUCA witness O'Donnell, the Commercial Group witnesses Chriss and Rosa, and CIGFUR II 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 Mr. Hevert's proxy groups of electric utilities. His comparable earning recommended ROE range was 9.0% to 10.0%. The Commission approved ROE of 9.9% is in the upper portion of his range. As testified by Mr. 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. Mr. Parcell testified that his comparable earnings analyses considers the recent historic and prospective ROEs for the groups of proxy utilities companies utilized by himself and DEP witness Hevert. He testified that his comparable earnings analyses reflect the actual ROEs 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 ROE for DEP below the earned ROEs 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 ROE 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 ROE of 9.9% is 10 basis points below Mr. Hevert's risk premium's implied ROE 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 Mr. 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% ROE is well within that range.

The Commission has carefully evaluated the DCF analysis recommendations of witnesses Parcell, Hervert, Polich, and O'Donnell, and the Commission gives no weight to these analyses. As shown on Commercial Group Exhibit CR-3, the lowest Commission approved ROE for a vertically integrated electric company for the period of 2014 through the hearing in 2017 was 9.2%. Mr Parcell's specific DCF results was 8.85%, Mr. Polich's was 8.48%, and the mid-point of Mr. 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 Mr. 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 ROE of 9.2%. The Commission determines that all of these DCF analyses in the current market produce unrealistic low results.

In addition, the Commission does not agree with DEP witness Hevert's sole use of analysts earning per share projections to calculate the DCF dividend growth DEC component. Witnesses Parcell, Polich, and O'Donnell all considered some historical information to calculate their DCF dividend growth components. Witnesses Parcell, Polich, and O'Donnell all testified that analysts' earnings per share growth forecasts are upwardly biased. The Commission concludes that investors also consider to some extent historical results in making investment decisions. In addition, the Commission concludes that Mr. Hevert's multi-stage DCF long-term GDP growth rate of 5.5%, which includes the 1929-2016 "real growth of GDP", is upwardly biased. As testified to by witnesses Parcell and Polich, a much more realistic long-term GDP growth rate of 4.22% based upon the projections of the Social Security Administration (SSA), the Energy Information Administration (EIA), and IHS Global Insights, as described by witness Polich, and the 4.35% SSA projections and the 4.2% EIA projection testified to by Mr. Parcell.

The Commission gives no weight to any of the witnesses CAPM analyses. The analyses of Mr. 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 ROE mid-point of 6.05% ,which is an outlier well below the 9.2% previously discussed. Witness Polich's CAPM weighted median ROE of 7.56% is also an outlier 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 Bond interest rate of 3.52%, which witness Parcell testified greatly exceeds the current level of long-term Treasury Bonds of about 2.8%. Mr. 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. Mr. Hevert's DCF dividend growth, component based solely on analysts' earning per share growth projections, without consideration of any historical results, is upwardly biased and unrealiable.

The ROE testimonies of Commercial Group witnesses Chriss and Rosa focused on the Commission approved ROEs authorized for vertically integrated electric utilities in 2014, 2015, 2018 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% ROE and to evaluate outlier ROE recommendations. CIGFUR II Witness Phillips' testimony focused on the RRA reports Major Rate Case Decisions. The 9.61% average authorized ROE for electric utilities included both vertically integrated electric utilities and distribution only electric utilities. As DEP is a vertically integrated electric utility, the Commission gives witness Phillips' ROE testimony limited weight as approved ROEs for distribution only electric utilities are generally lower than Commission approved ROE's for vertically integrated electric utilities.

The 9.9% ROE approved in this proceeding for DEP is also consistent with the 9.9% ROE the Commission approved for DNCP in the Order dated December 22, 2016, 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 return on equity provided for here 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 a capital structure of 53% members' equity and 47% long-term debt. 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 is just and reasonable.

In her pre-filed direct testimony, Company witness Bateman testified that the Company's revenue requirement was determined using capitalization ratios of 53% members' equity and 47% long-term debt which is the Company's targeted capital structure that this Commission found reasonable and in the public interest in the DEP Sub 1023 Rate Order.

Company witness De May also stated in his direct testimony that the 53% equity ratio proposed by the Company will support its financial integrity by helping enable access to capital at reasonable rates. Witness De May testified that the Company maintains its equity ratio at 53% as part of its continuing efforts to maintain its financial profile and credit ratings. He explained that if the Commission were to approve a lower equity ratio, the Company's financial profile likely would come under pressure because DEP either would reduce its actual equity ratio, which would have the effect of increasing its financial risk, or risk the dilution of its income and cash flow-based credit metrics.

Company witness De May testified in support of the capital structure component of the Stipulation that the 52% to 48% equity-to-debt capital structure is reasonable and appropriate when viewed in the context of the overall Stipulation. He testified all other things equal, credit rating agencies view the constructiveness of the regulatory environment and the company's ability to timely recover prudently incurred costs as important ratings criteria in their assessment of the company's credit quality. He testified the Stipulation, on a stand-alone basis, demonstrates an ability to do this and he believes its approval would be viewed by the ratings agencies as constructive and equitable.

With respect to capital structure, in Public Staff Parcell's direct testimony, he recommended a capital structure with 50% common equity and 50% long-term debt. Witness Parcell testified that DEP witness De May stated in his pre-filed direct testimony that DEP's actual common equity on December 31, 2016 was 54.2% and witness De May stated in his rebuttal testimony that through June 2017, DEP has maintained a 13-month actual average common equity of 53.5% per the Commission's Form E.S-1.

Public Staff witness Parcell testified in support of the Stipulation that the 52% common equity ratio in the proposed Stipulation reflects a compromise between DEP's 53% proposed equity ratio and his proposed 50% equity ratio. It does, however, incorporate a reduction in DEP's equity ratio in comparison to DEP's recently authorized common equity ratio of 53% equity and 47% long-term debt.

Mr. 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 commissions in regulatory environments considered above average, and 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.

The Commission concludes that a capital structure of 52% common equity and 48% long-term debt is appropriate for the Company in this proceeding. The Commission recognizes that, as discussed by witness De May, a strong equity component is a factor in determining the Company's credit rating.

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 ROE 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 ten years. The Commission accepts this testimony as credible, probative and entitled to substantial weight, as well as the testimony of witnesses Hevert and Parcell regarding changing economic conditions and their effect upon customers. Finally, the Commission gives significant weight to the Stipulation, and the benefits that it provides to customers.

As in the case of the 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 the higher rates which some customers will find difficult to pay.

Accordingly, the Commission finds and concludes that the Stipulating Parties' recommended capital structure of 52% common equity and 4*% 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 DEP September 8, 2017, issued long-term debt First Mortgage Bonds Taxable. 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 IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 21

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

Company witness McGee provided testimony in support of the proposed base fuel and fuel-related cost factors in the Company's Application. These factors included the Experience Modification Factors (EMFs) as proposed by the Company in its 2016 fuel and fuel-related cost adjustment proceeding in Docket No. E-2, Sub 1107 (Sub

1107). As stated in witness McGee's testimony in that proceeding, these proposed factors are based upon the Company's forecasted fuel and fuel-related costs for the period December 1, 2016, through November 30, 2017. Witness McGee explained that DEP proposed to adjust the factors used in this proceeding, as necessary, to conform to the factors approved by the Commission in Docket No. E-2, Sub 1146. She testified that the Company's North Carolina retail adjusted fuel and fuel-related expense for the test period ending December 31, 2016, was $807,561,119. Witness McGee explained that she calculated this amount using the proposed base fuel and fuel-related cost factors proposed in Sub 1107 and the North Carolina retail test period megawatt-hour sales as adjusted for weather and customer growth.

The Stipulating Parties agreed to the following fuel and fuel-related cost factors, by customer class, incorporating those factors approved by the Commission in Sub 1107 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

The Stipulating Parties also agreed 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.

No intervenor contested these provisions of the Stipulation. The Commission finds and concludes, based on the Stipulation, that the North Carolina retail base fuel expense for this proceeding is $807,561,119, and that 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 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..

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 22

The evidence supporting this finding of fact and conclusion is contained in the Stipulation.

Paragraph III.R. of the Stipulation states that DEP will reduce its amount of coal inventory included in working capital by the establishment of an increment rider, effective the date of the base rates approved in this Order and until the inventory levels reach a 35-day supply, allowing the Company to recover the additional costs of carrying coal inventory in excess of a 35-day supply (priced at $76.11 per ton). According to the Stipulation, the rider will be terminated 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 on a sustained basis. For the purpose of determining when the Company's coal inventory has reached the appropriate levels to trigger (b) above, three consecutive months of total coal inventory of 37 days or less will constitute a sustained basis. However, the Company may request an extension of the January 30, 2020, date. Further, the Stipulation states that the interest on any under- or over-collection be set at the Company's net-of-tax overall rate of return, as approved by the Commission in this Order. The Company will adjust the rider annually, concurrently with DEP's Demand-side Management / Energy Efficiency (DSM/EE), Renewable Energy and Energy Efficiency Portfolio Standard (REPS), Joint Agency Allocation (JAAR), and Fuel

Adjustment riders. Last, pursuant to the Stipulation, the Company, in consultation with the Public Staff, will conduct an analysis by December 31, 2018, showing the appropriate coal inventory level given market and generation changes since the Company's rate case in Docket No. E-2, Sub 1023.

No parties objected to this portion of the Stipulation. The Commission finds this provision of the Stipulation to be just and reasonable to all the parties.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 23

The evidence supporting this finding and conclusion 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 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) that indicates how often the average customer has a sustained outage, and the System Average Interruption Frequency Index (SAIFI) that 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.

Company witnesses Fountain and Simpson have demonstrated that the Company has performed satisfactorily in areas of customer satisfaction and reliability during the test period. The Company is expected to promptly follow up and resolve any service-related customer complaints raised at the public hearings. Therefore, consistent with Paragraph IV.I. of the Stipulation the Commission finds and concludes that the overall quality of electric service provided by DEP is adequate.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 24

The evidence supporting this finding of fact and conclusion is contained in the Stipulation, the testimony of Company witnesses Fountain and Simpson, and the testimony of Public Staff witness Floyd.

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. 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.

Public Staff witness Floyd testified that he believes 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 require additional reporting, which can assist the Commission and Public Staff in understanding Power/Forward Carolinas and evaluating its cost-effectiveness.

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 North Carolina 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.

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.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 25

The evidence supporting this finding of fact and conclusion 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.

Public Staff witness Peedin testified that DEP did not commission a new lead-lag study for this case because the existing study was less than ten years old, and the Company believed it was still valid. She recommended that the Commission direct the Company to prepare and file a lead-lag study in its next rate case. In his rebuttal, Company witness Doss testified that the Company agreed with this recommendation and would prepare and file an updated lead-lag study as part of its next rate case application. Paragraph IV.E. of the Stipulation provides that DEP shall prepare and file a lead-lag study in its next general rate case. The Commission finds this provision of the Stipulation to be just and reasonable.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 26

The evidence supporting this finding and conclusion 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 SCP cost of service study. Witness Hagar 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 pm. The Company's system peak occurred on Tuesday, January 19, 2016 in the hour ending at 8:00 am. 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 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 should be allocated based on the summer peak.

The Public Staff historically has supported the use of the 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.

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.

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 should be allocated based on the summer peak.

Although the Public Staff has traditionally supported SWPA cost allocation, it is not unreasonable for the Stipulating Parties to have agreed to the use of SCP for this proceeding. Therefore, based upon consideration of the Stipulation in its entirety, the Commission gives the Stipulation substantial weight in resolving the cost allocation issue. However, the Commission's acceptance of the SCP methodology in this proceeding shall not be precedent for and may not be cited as such in future proceedings.

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

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 27

The evidence supporting this finding and conclusion is contained in the Stipulation, DEP' 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 advanced metering infrastructure (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 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 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.

Public Staff witness Floyd outlined the four fundamental principles the Public Staff follows when assigning a proposed revenue increase: (1) using a plus or minus "band of reasonableness", such that to the extent possible, the class rates of return after the rate changes stay within this band of reasonableness; (2) moving each customer class toward parity with the overall jurisdictional return on rate base; (3) limiting the combined rate base revenue increase for any customer class to no more than two percentage points greater than the overall jurisdictional increase; and (4) minimizing subsidization of customer classes by other classes.

In Paragraph IV.F. of the Stipulation, the Stipulating Parties agreed on the following with regard to the revenue increase and the rate schedules to be filed by the DEP in this proceeding:

1. To the extent possible, the Company shall assign the approved revenue increase consistent with the principles regarding revenue apportionment described in the testimony of Public Staff witness Floyd.

2. The rate class revenue requirement for DEP rate schedules shall be modified to reflect the adjustments in revenues set forth in Settlement Exhibit 1, and shall further be defined once the Commission resolves all issues in this proceeding.

3. The Parties agree that the Company shall implement the rate design proposed by Company witness Wheeler within his direct testimony, filed contemporaneously with the Company's Application in this docket, as adjusted by this Stipulation, modified as follows:

   a. The Stipulating Parties agree that the Company may increase its BCC for Schedule RES to $14.00 per month. The Stipulating Parties further agree that the Company may increase its BCCs 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 TOU 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.

Kroger entered into a Settlement Agreement with the Company that provided that Kroger would not oppose the settlement between the Company and the Public Staff provided the Company agreed to include the language of sub-paragraph IV.F.(d) in the Stipulation with the Public Staff. The Commercial Group also entered into a Settlement Agreement with the Company, in which the Company agreed to include the language of sub-paragraph IV.F.(d) in the Stipulation with the Public Staff, and also agreed to work with interested customers to investigate the issues regarding Rider SS that were raised in the direct testimony of the Commercial Group filed in this proceeding.

Based on the testimony of witnesses Wheeler and Floyd, as well as the agreement of the Stipulating Parties, the Commission finds and concludes that the rate design provisions of Paragraph IV.F. of the Stipulation are just and reasonable to all parties in the light of all the evidence presented.

EVIDENCE IN SUPPORT OF FINDINGS OF FACT AND CONCLUSIONS NOS. 28-29

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

Based upon the evidence in this proceeding and the cumulative testimony and evidence supporting the individual components of the Stipulation discussed throughout this Order, including the discussion and analysis related to the proper overall rate of return and return on common equity for use in this proceeding, the Commission finds, in the exercise of its independent judgment, that the Stipulation in this case is just, reasonable, and appropriate for use in this proceeding. Further, as set out in Findings of Fact Nos. 30-58, the Commission has made determinations regarding the disputed issues over which the Stipulating Parties were not able to reach agreement, i.e., issues regarding coal ash costs, coal ash sales, and the JRR.

The following schedules summarize the gross revenue and the rate of return that the Company should have a reasonable opportunity to achieve based on the determinations made herein. These schedules, illustrating the Company's gross revenue requirement, incorporate the findings and conclusions made by the Commission in this Order. As reflected in Schedule I, and as impacted by the other findings in this Order, DEP is authorized to increase its annual level of gross revenues by $142,304,000, before reduction by the EDIT Rider.

SCHEDULE I

DUKE ENERGY PROGRESS, LLC
North Carolina Retail Operations
Docket No. E-2, Sub 1142
STATEMENT OF OPERATING INCOME
For the Twelve Months Ended December 31, 2016
(000's Omitted)

Item	Present Rates	Approved Increase	Approved Rates
Electric operating revenues:			
Sales of electricity	$3,101,700	$142,304	$3,244,004
Other revenues	47,823	0	47,823
Total electric operating revenues	$3,149,523	$142,304	$3,291,827
Electric operating expenses:			
Operations and maintenance:			
Fuel used in electric generation	$ 637,993	$ 0	$ 637,993
Purchased power	322,537	0	322,537
Other O&M expenses	881,733	455	882,188
Depreciation and amortization	533,569	0	533,569
General taxes	99,877	0	99,877
Interest on customer deposits	8,662	0	8,662
Net income taxes	186,664	52,501	239,165
Amortization of investment tax credit	(2,093)	0	(2,093)
Total electric operating expenses	$2,668,942	$ 52,956	$2,721,898
Net operating income for return	$ 480,581	$ 89,348	$ 569,929

SCHEDULE II

DUKE ENERGY PROGRESS, LLC
North Carolina Retail Operations
Docket No. E-2, Sub 1142
STATEMENT OF RATE BASE AND RATE OF RETURN
For the Twelve Months Ended December 31, 2016
(000's Omitted)

Item	Present Rates	Approved Increase	Approved Rates
Electric plant in service	$16,462,655	$ 0	$16,462,655
Accumulated Depr. & Amortization	(7,601,372)	0	(7,601,372)
Net electric plant in service	8,861,283	0	8,861,283
Materials and supplies	632,680	0	632,680
Operating funds per lead lag study	141,830	9,437	151,267
Unamortized debt	30,261	0	30,261
Regulatory assets and liabilities	445,152	0	445,152
Customer deposits	(121,384)	0	(121,384)
Accumulated deferred income taxes	(1,998,986)	0	(1,998,986)
Operating reserves	(66,990)	0	(66,990)
Construction work in progress	102,930	0	102,930
Total original cost rate base	$ 8,026,776	9,437	$ 8,036,213
Rate of Return	5.99%		7.09%

SCHEDULE III

DUKE ENERGY PROGRESS, LLC
North Carolina Retail Operations
Docket No. E-2, Sub 1142
STATEMENT OF CAPITALIZATION AND RELATED COSTS
For the Twelve Months Ended December 31, 2016
(000's Omitted)

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
Present Rates-Original Cost Rate Base				
Long-Term Debt	48.00%	$3,852,853	4.050%	$156,041
Common Equity	52.00%	4,173,924	7.78%	324,540
Total	100.00%	$8,026,776		$480,581
Approved Rates – Original Cost Rate Base				
Long-Term Debt	48.00%	$3,857,382	4.050%	$156,224
Common Equity	52.00%	4,178,831	9.90%	413,704
Total	100.00%	$8,036,213		$569,928

EVIDENCE IN SUPPORT OF FINDINGS OF FACT AND CONCLUSIONS NOS. 30-40

In their direct testimony, DEP witnesses contended that the coal ash costs included in the Company's rate request are costs of complying with new laws and regulations. Specifically, ash basins are being closed pursuant to the United States Environmental Protection Agency (EPA) "Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities; Final Rule" published in the Federal Register Vol. 80, No. 74, on April 17, 2015, (CCR Rule) and the North Carolina Coal Ash Management Act (comprised of Session Law 2014-122, Senate Bill 729; Session Law 2015-110, Senate Bill 716; and Session Law 2016-95, House Bill 630; collectively referred to as “CAMA”).

In her initial filed testimony, DEP witness Bateman summarized the Company’s request to recover the costs of ash basin closure and compliance from January 1, 2015, to August 31, 2017. She stated that the total system spend by DEP on coal ash basin closure during that period is $482.7 million ($98.7 million in 2015, $212.7 million in 2016, and $171.3 million in the 2017 projected period). (T 6, p 123)

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

DEP witness Kerin described the Company’s coal-fired generation resources, the history of its ash handling, and the history of applicable regulations for coal ash management. He generally discussed the requirements of the CCR Rule, CAMA, and consent or settlement agreements and orders affecting closure of ash basins and other aspects of CCR management. His exhibits included the amount of ash and history of disposal for each plant, initial closure plans for ash basins, a breakdown of expenditures in 2015-2016 for coal ash compliance at each plant site, and a plant-by-plant summary of ash management cash flows for Asset Retirement Obligation (ARO) purposes. Mr. Kerin testified that DEP's actions and expenditures have been reasonable, prudent, cost-effective, and designed to meet existing legal requirements. He also summarized DEP's request for recovery of ongoing CCR compliance costs, testifying that those ongoing costs are reasonable, prudent, and cost-effective options for ongoing CCR compliance.

INTERVENOR TESTIMONY

Public Staff witnesses Garrett and Moore testified that they investigated the prudence and reasonableness of costs incurred by 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. (T 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, which they described in further detail in their testimony. 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). (T 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 Mayo and Roxboro. (T 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 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 ash beneficiation projects at each site capable of annually processing 300,000 tons of ash to specifications appropriate for cementitious products, with all processed ash to be removed from the impoundments located at the sites. (T 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 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 ash of the additional 70,000 tons of ash from Weatherspoon. (T 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 ash on-site without incurring the added expense associated with the off-site transfer and disposal. (T 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 ash on-site without having to incur the significant costs associated with off-site transportation costs and construction of rail handling equipment. (T 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. (T 18, p 154)

As a result of DEP's unnecessary actions to transport 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 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 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 "Mountain Energy Act") amended the required completion date for closing the two 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. (T 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 ash materials off-site. Witnesses Garrett and Moore also testified that the ash processing costs expended at the Asheville facility relative to the amount of ash that had been removed off-site were unreasonable. (T 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 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 ash, which resulted in the unnecessary double-handling of some ash on site; (b) DEP's decision to transport excavated ash to the Waste Management landfill in Homer, Georgia, rather than transporting all of the excavated 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 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. (T 18, pp 173-76)

DEP REBUTTAL TESTIMONY

DEP witness Kerin filed rebuttal testimony on November 6, 2017, in which he noted that Public Staff witnesses Garrett and Moore had conducted a robust analysis and investigation. He indicated that he agreed with a majority of their conclusions, but stated that given the scope and magnitude of the information they had to investigate and the time in which they had to conduct their investigation, they missed or overlooked key facts in several of their recommendations. (T 20, pp 31-33)

First, Mr. Kerin disagreed with witnesses Garrett and Moore's conclusion that an onsite landfill could have been built at the Sutton site in lieu of DEP's decision to initially transport ash to the Brickhaven while the on-site landfill was being permitted and constructed. He also disagreed with their conclusion that an onsite landfill could have been built at the Asheville site in lieu of transporting the ash materials off-site. (T 20, pp 33-40)

With regard to Sutton, Mr. Kerin testified that DEP has constructed and is operating an on-site landfill at the Sutton facility, and agreed that the on-site facility was a good choice for the site. He testified, however, that the moratorium in place in 2014 and 2015, along with other requirements related to dewatering and the determination of when a coal ash excavation is complete, limited the construction of an on-site landfill in the footprint of an existing CCR impoundment. (*Id.*)

Mr. Kerin also testified that witnesses Garrett and Moore used a "perfect world" scenario and made incorrect assumptions regarding the ability to permit and construct a CCR landfill without consideration of the inherent uncertainty of permitting any type of landfill, particularly during the regulatory and political environment in 2014. He noted that the ash quantity at Sutton was increased from earlier estimates, and the low elevation of the basins, with much of the ash lying below the historic groundwater table, requires extra work to dredge and dewater coal ash materials. Mr. Kerin described unanticipated delays, such as DEQ's announcement requiring an environmental justice review of each Duke Energy CCR landfill going forward before a landfill permit would be issued. He also speculated that potentially other events could have led to additional delays. Mr. Kerin testified that DEP could not have started permitting the design for an on-site landfill at Sutton in June of 2014, as suggested by witnesses Garrett and Moore, because CAMA did not become law until September 20, 2014, and DEP did not submit its initial Excavation Plan to DEQ until November 13, 2014, which included construction of the on-site landfill, ash basin excavation activities, initiation of basin dewatering, site preparation, ash basin preparation, and ash removal from the basins. (*Id.*)

Mr. Kerin also indicated that witnesses Garrett and Moore erroneously assumed a "production rate" of 200,000 tons per month, but he indicated that this value actually reflects the "ability to receive rate" of the new on-site permitted landfill, and could not be assumed for the overall production rate. Mr. Kerin instead stated that the production rate was expected to vary between 150,000 and 200,000 tons per month based on site conditions. (T 20, p 41)

As a final issue regarding Sutton, Mr. Kerin noted that while the two specific landfill liner components identified by witnesses Garrett and Moore were not specifically required for other new landfill sites across the State, the location of the newly constructed Sutton CCR landfill, immediately adjacent to the existing coal ash surface impoundments, required their use to effectively monitor the new landfill. Mr. Kerin noted that these additional liners are necessary to distinctly monitor the new landfill's performance, isolating it from any influence from the adjacent older coal ash basins, both now and in the future. Otherwise, it would be difficult to discern whether the new landfill liner system was operating properly (or leaking), or whether groundwater monitoring wells around the landfill were actually detecting impacts from the adjacent coal ash basins. (T 20, pp 50-51)

Regarding Asheville, Mr. Kerin testified that he disagreed with witnesses Garrett and Moore that an on-site landfill could have reasonably been built at the Asheville site. He testified that DEP had previously evaluated siting and construction of an on-site landfill as early as 2007 at the Asheville site, but earthquake and seismic issues, along with the site's physical proximity to the French Broad River prevented this option. Further, he testified that the Mountain Energy Act required construction and startup of a new combined cycle power plant at the site of the 1982 coal ash basin, and also required large site areas be reserved for the construction laydown areas necessary to support efficient construction of the new plant. As a result of these requirements, Mr. Kerin testified that there was no longer sufficient land on which to build an on-site landfill in the 1964 basin. (T 20, pp 42-44)

With regard to the ash handling costs at Asheville, Mr. Kerin noted that the price per ton for ash disposal that DEP paid at the Asheville site was reasonable, and that DEP was able to negotiate more favorable rates in December of 2016. Mr. Kerin disagreed with the quantity of ash that witnesses Garrett and Moore calculated was moved off-site, stating that the total quantity of ash excavated and transported from the Asheville site is approximately 1.4 million tons (~550,000 tons from the 1982 basin to the 1964 basin and 850,000 tons moved off-site). He noted that this figure excludes the 354,000 tons of ash excavated and transported to the Asheville Airport structural fill project. (T 20, pp 44-47)

Regarding Weatherspoon, Mr. Kerin testified that Buck, H. F. Lee, and Cape Fear have been chosen as the three sites for beneficiation based on DEP's calculation of the sites offering the best economic value to customers while meeting CAMA compliance. While DEP was able to negotiate agreements with offtakers to the South Carolina concrete industry for an average volume of 230,000 tons per year, it could not guarantee a larger volume sufficient to meet the 300,000 tons per year required by CAMA. Mr. Kerin agreed with witnesses Garrett and Moore's recommendation that DEP continue to make commercially reasonable efforts to identify additional sites for cost-effective beneficial reuse of ash. (T 20, pp 51-52)

COMMISSION REVIEW OF EVIDENCE AND CONCLUSIONS

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

> the standard for determining the prudence of the Company's actions should be whether management decisions were made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or reasonably should have been known at that time. The Commission agrees that this is the appropriate standard to be used in judging the various claims of imprudence that have been put forth in this proceeding…and adopts it as the standard to be applied herein. The Commission notes that this standard is one of reasonableness that must be based on a contemporaneous view of the action or decision under question. Perfection is not required. Hindsight analysis -- the judging of events based on subsequent developments — is not permitted.
>
> 78 North Carolina Utilities Commission Report, 238 at 251-52 (1988).

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

During the hearing, DEP witness Kerin, on cross-examination, agreed that Duke Energy identified several guiding principles to help direct its closure activities. These included protecting groundwater, protecting from external events, and minimizing impacts to local communities. (T 17, p 79) In addition, Mr. Kerin agreed that selecting the most cost-effective option would also be viewed as a guiding principle. (T 17, pp 90-91) The Commission agrees that these principles help provide a framework to evaluate the reasonableness and prudence of decisions made by the utility, particularly in circumstances where DEP selected closure options that may have increased the overall costs it faced in part to reduce further risk. Nonetheless, in some cases, as pointed out by Public Staff witnesses Garrett and Moore, it appears that closure option decisions were made by DEP that were not entirely consistent with these principles, particularly the cost-effectiveness principle, and resulted in imprudently incurred costs. Using a plant by plant approach, the Commission discusses the concerns raised by the parties below:

Prudence of Sutton Closure Costs

Public Staff witnesses Garrett and Moore's general premise is that DEP's on-site landfill at Sutton would have been the most reasonable and prudent closure method had DEP started the permitting and construction process earlier. This would have eliminated the need for any off-site transportation of coal ash from Sutton to Brickhaven, reducing the closure costs incurred by DEP at Sutton by over $80 million. It is clear that in light of the aggressive timeframe for closure of high-priority sites, the timing of the decisions being made weighs heavily in this analysis.

Public Staff witnesses Garrett and Moore took exception to the position taken by DEP that the timing of DEP's decision to proceed with an on-site landfill at the Sutton facility was impacted by the moratorium enacted in Section 5.(a) of CAMA in 2014. (T 18, pp 148-149) Section 5.(a) provides:

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

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

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

The moratorium did not, however, impact in any way DEP's ability to construct a new on-site landfill on what would be considered a greenfield site, i.e. a site that was not "located wholly or partly on top of a facility that is, or was, being used for the disposal or storage of such combustion products." DEP witness Kerin agreed that the moratorium did not apply to on-site greenfield landfills. (T 17, pp 69-70)

Public Staff witnesses Garrett and Moore presented evidence indicating that the conceptual analysis that was prepared for DEP prior to determining its closure plan at Sutton evaluated both greenfield and CCR landfill options, both of which were significantly more cost-effective than all off-site disposal options. (T 18, pp 148-49) The on-site landfill that was ultimately permitted and constructed at Sutton was sited in a greenfield area, and was therefore not subject to any delays associated with the moratorium. Therefore, the Commission finds and concludes that the moratorium is not relevant in the discussion of the timing of the Sutton on-site landfill.

In rebuttal, DEP witness Kerin testified that Public Staff witnesses Garrett and Moore used “perfect world” scenarios, and that their assumptions on the permitting, construction, and excavation rates were not reasonable. Mr. Kerin indicated that witnesses Garrett and Moore erroneously assumed a “production rate” of 200,000 tons per month, but he indicated that this value actually reflects the “ability to receive rate” of the new on-site permitted landfill, and could not be assumed for the overall production rate. However, Mr. Kerin affirmed on cross-examination that that the permitting and construction schedules relied on by witnesses Garrett and Moore were based on DEP’s assumptions, as well as the excavation and placement rate estimates developed by DEP. (T 17, pp 91-96) With regard to the ash excavation and placement rates, the Public Staff presented multiple sources supporting the 200,000 ton excavation rate as being reflective of DEP’s assumptions, not perfect world assumptions. (T 20, pp 83; 88-89, 93). In addition, Mr. Kerin also agreed that DEP’s closure schedule included disposal of coal ash from areas that were not subject to the August 1, 2019, closure deadline, indicating that DEP’s schedule was more aggressive than necessary to achieve closure within the timeframe provided. (*Id.* at 95)

When presented with the documents described above, Mr. Kerin indicated that these documents look like early production schedules, based on linear production estimates. He indicated that this information would be updated over time, as the excavation proceeded. (T 20, pp 95-96).

The Commission finds that it was reasonable for the Public Staff to rely on the information provided by DEP in response to Public Staff data requests regarding the construction, permitting, and operation of an on-site landfill facility at Sutton, while taking into consideration the purpose for which of the documents were created. These documents help provide relevant insight in this prudency analysis as to the information available to management at DEP at the time the closure decisions in question were being made. Any suggestion by DEP that the documents should now be revised to reflect new estimates would be hindsight analysis, which is not appropriate for a prudence review. .

One other key question raised by the Public Staff dealt with the date on which DEP began taking firm steps towards one or more of the possible closure options at Sutton. Public Staff witnesses Garrett and Moore testified that DEP began to evaluate structural fill options for the Sutton facility in March and April 2014. Public Staff witness Lucas testified that in July of 2014, DEBS, on behalf of DEC and DEP, issued a bidding event for the excavation, transportation, and off-site storage of the full volume of ash at four sites, including Sutton, and that DEBS entered into a contract on November 12, 2014, with Charah, LLC, that included initial excavation work at Sutton. (T 18, pp 232-33) However, Public Staff witnesses Garrett and Moore testified that DEP did not submit its site application and landfill construction application for Sutton to DEQ until May 2015. Witnesses Garrett and Moore testified that had DEP acted on the same schedule to proceed with on-site closure options that it did with off-site options, then the need – and time - for selection of off-site disposal options for Sutton would have been eliminated. (T 18, pp 148-50)

DEP witness Kerin testified that several events occurred after the start of the on-site landfill permitting process that extended the timeframe for construction of the facility, including an increase in the estimated ash volumes at the Sutton facility and an unexpected environmental justice review. He pointed to these events as evidence of the uncertainty with relying on the on-site landfill as their sole closure option. By their very nature, however, these "unexpected" events are the types of circumstances of which DEP would not have reasonably known at the time it was making its decisions, and therefore are not appropriate for consideration as to the prudency of DEP's decisions at the time the costs were incurred. Further, the Commission finds that to the extent these events impacted DEP's ability to begin quickly excavating from the site, they could have equally impacted the excavation schedule for the off-site structural fill site.

Public Staff witnesses Garrett and Moore also testified that DEP minimized or overlooked events that resulted in delays at the Brickhaven off-site structural fill facility and increased costs associated with this disposal option, including litigation resulting from local community opposition and settlements. DEP did not dispute these findings. Garrett and Moore further testified that the decision to transport a portion of the coal ash off-site conflicted with the utility's guiding principles of managing coal ash on-site to protect neighboring communities and choosing the most cost-effective closure option, while providing no additional groundwater protection benefits.

Other delays cited by DEP relating to dewatering processes and the uncertainty with regard to basin closure requirements were applicable to all of the closure options under consideration, not only the siting of an on-site greenfield landfill. The Commission therefore finds that these other potential causes for delay presented by DEP do not impact using an on-site greenfield option to close the Sutton site any differently than they would impact the closure of another high priority site using other closure options.

As pointed out by Public Staff witnesses Garrett and Moore and by DEP witness Kerin, the General Assembly included a variance provision in G.S. 130A-309.213(a) that was designed to provide relief from the closure deadlines established in CAMA, provided that the owner of an impoundment seeking a variance makes an adequate demonstration that it has substantially complied with all other requirements and deadlines established in CAMA, have made good faith efforts to comply with the applicable closure deadlines, and “that compliance with the deadline cannot be achieved by application of best available technology found to be economically reasonable at the time and would produce serious hardship without equal or greater benefits to the public.” (T 17, pp 102-05) The circumstances that resulted in additional unexpected delays or extended timeframes described by DEP reflect the type of circumstance where it could be appropriate for a utility to seek a variance, if necessary for compliance, rather than select a significantly more costly closure option that provided little or no additional benefit to local communities, customers, or environmental safety.

Therefore, the Commission finds that DEP's decision to incur unnecessary costs to transport coal ash off-site from Sutton to the Brickhaven structural fill facility was not reasonable in light of lower cost, on-site disposal options, and agrees with the Public Staff that the costs associated with transporting the coal ash off-site should be disallowed from DEP's request in this proceeding.

With regard to DEP's construction of the secondary liner system for the Sutton on-site landfill, DEP witness Kerin's statement that 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, seems to imply that the landfill construction standards promulgated by DEQ are not sufficient. The Company has failed to show that DEQ's landfill construction standards are insufficient, and therefore the Commission finds that those costs in excess of the State-mandated requirements should be excluded.

Prudence of Asheville Closure Costs

The Public Staff's position concerning the expenditures by DEP at the Asheville facility focuses on three main questions. First, was there an on-site option that should have been more fully evaluated by DEP prior to committing to transport all of the waste off-site; second, was DEP's management of its ash processing from the 1982 basin reasonable; and third, were the off-site disposal options that were selected and the costs associated with those options reasonable? The Commission discusses each of these points in further detail below.

As previously discussed, DEP agreed that one of its guiding principles was to minimize impacts to local communities, such as through reduced trucking and traffic congestion, and one way that helped meet this principle was through management of ash on-site to the greatest extent possible. Public Staff witnesses Garrett and Moore also testified that on-site management generally results in much lower costs, lower risk compared to off-site disposal, and to some extent may generate less controversy than off-site disposal. (T 18, pp 152-153) DEP witness Kerin agreed that any time you can minimize the amount of time ash has to be handled multiple times, it would provide savings on the overall operation, and that transportation costs are one of the largest costs associated with basin closure. (T 17, p 81) He also agreed that DEP looks at the feasibility analysis of on-side landfills before looking at off-site options. (T 17, p 89).

Public Staff witnesses Garrett and Moore testified that as far back as 2007 DEP had previously considered the 1964 Ash Basin as a possible location for an on-site landfill, but indicated that seismic issues and its proximity to the French Broad River prevented this option. (T 18, pp 156) Mr. Kerin stated that upon passage of the Mountain Energy Act in 2015, space became very limited at the Asheville facility due to the timing and space needed for construction of the combined cycle facility within the footprint of the 1982 basin. He stated that because of this schedule, there was not sufficient time to build a landfill within the 1964 basin. (T 17, p 84)

Garrett and Moore agreed that timing was a factor and the CCR landfill moratorium would have impacted what on-site options may have been available at the Asheville facility. However, with the expiration of the moratorium in August 2015 and the enactment of the Mountain Energy Act that provided a three-year extension on the closure deadlines for the Asheville facility, they believed it was appropriate for DEP to have re-evaluated on-site options at that time to determine their feasibility in order to reduce much more significant costs associated with transportation of the ash materials off-site. (T 18, p 159). DEP indicated, however, that they had not re-evaluated the feasibility of an on-site landfill at the Asheville facility (T 20, pp 120-121).

The Commission notes that Public Staff witnesses Garrett and Moore did not base their adjustment at Asheville on DEP's failure to complete an updated feasibility analysis for an on-site landfill following the passage of the Mountain Energy Act, but they did indicate that the construction of an on-site landfill would have potentially saved significant costs that were incurred transporting the waste off-site. The Commission agrees that where closure deadlines and other significant regulatory requirements change, it would be prudent for a utility to re-evaluate the feasibility of on-site closure options in order to reduce costs. The Commission finds that upon enactment of the Mountain Energy Act it was unreasonable for DEP not to have evaluated its closure plan for the 1964 basin to determine if an on-site landfill would have been technically feasible and would have potentially reduced costs associated with managing the remainder of the ash materials at the Asheville site.

Public Staff witnesses Garrett and Moore also recommended that DEP be allowed to recover only those costs that were associated with excavation of the coal ash and stockpiling ash on a temporary basis, but not the costs associated with transporting ash in the 1982 Basin for placement in the Ash Stack on the 1964 basin. (T 18, p 175) They opined that it would have been more cost-effective for DEP to have immediately transported the materials off-site, rather than creating an Ash Stack in the 1964 Basin, and that the double-handling not only increased costs, but also complicated further closure options for the 1964 Basin. (*Id.*) Further, Garrett and Moore indicated that:

> due to the closer proximity of the Cliffside landfill to the Asheville facility (approximately 60 miles one way) as compared to the R&B landfill in Homer, Georgia, (approximately 128 miles one-way), as well as the higher tipping fees associated with the R&B landfill relative to the placement fee for the Cliffside landfill, DEP should have exclusively utilized the Cliffside landfill to handle the CCR disposed off-site from the Asheville facility. (T 18, p 176)

DEP witness Kerin opined, however, that moving the amount of ash from Asheville to Cliffside in the amount of time that the Company had available would have been virtually impossible, and Garrett and Moore's contentions that it could have been done were incorrect. (T 20, p 103) DEP indicated that the position was based on the assumption that the movement of ash would have taken place over a six-month period. (T 18, p 200)

On cross-examination, however, Mr. Kerin agreed that, based on DEP''s own ash tracking records, DEP had transported an average of over 150,000 tons per month of ash during the six-month period from March 2016 between the Ash Stack, the Cliffside landfill, and the Waste Management Facility in Homer, Georgia (Public Staff Kerin Rebuttal Cross Examination Exhibit Number 4). Mr. Kerin also agreed that had DEP instead accomplished an average of approximately 71,000 tons per month from the facility during the period from passage of the Mountain Energy Act in June 2015 until the 1982 Basin had to be turned over for construction of the combined cycle facility in September 2016, it could have hauled all of the ash material without having to place any ash in the Ash Stack in the 1964 Basin. Further, (*Id.*; T 20, p 112)

The Commission agrees with the Public Staff that every effort should be made to reduce the need to double-handle ash materials to reduce costs, and that cost recovery should only be allowed in circumstances where the utility can affirmatively demonstrate that it did not have sufficient timing, space, or capacity to accommodate the handling of materials without double-handling. DEP indicated that it could not move the quantity of ash in question over the timeframe available, but based on its own tracking data, DEP ash processing at Asheville was very inconsistent over time. The Commission agrees that had DEP managed the excavation and off-site transportation in a more efficient manner, the need for handling larger quantities of ash over the short timeframe, discussed by DEP witness Kerin, could have been avoided. Therefore, the Commission agrees with the Public Staff and finds that the costs associated with transportation of ash materials from the 1982 Basin to the Ash Stack in the 1964 Basin was imprudent, and those costs should be disallowed from recovery in this proceeding.

Public Staff witnesses Garrett and Moore also opined that the transportation costs incurred by DEP for the transportation of ash material to the DEC Cliffside landfill appear excessive compared to the transportation costs on a per-mile basis associated with the Waste Management contract and truck hauling contracts entered into by DEP at other facilities. (T 18, p 176; <u>see also</u> Public Staff Garrett and Moore Confidential Supplemental Exhibit 8) They therefore recommended that the Commission adjust the off-site disposal rate to reflect the lower per-ton mile rate. DEP witness Kerin stated that

> The Company believes that the "all-in" blended contract price per ton had for the initial scope of work was reasonable. As we gained greater experience with excavation of the Asheville basins, however, DE Progress

was able to negotiate a more favorable all-in rate in December of 2016, an 18% decrease from the original blended rate. (T. 20, pp 44-45)

The Commission finds that Garrett and Moore's comparison of transportation costs at the Asheville facility to other transportation contracts entered into by DEP at other facilities is reasonable and provides a sufficient basis to determine that the "all-in" blended contract price per ton DEP initially negotiated was excessive and therefore imprudent.

Other Determinations

Public Staff witnesses Garrett and Moore discussed some facilities with which they did not take any exception with regard to costs incurred to date, but raised issues for the Commission's consideration. Regarding Weatherspoon, they 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 for beneficial use in the concrete industry, since this option was the lowest cost closure option selected for this site, but determined that Duke Energy 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 to potentially utilize lower cost closure options instead of cementitious beneficiation. The Commission agrees with witnesses Garrett and Moore that the potential cost savings associated with an alternate selection would have justified additional efforts by Duke Energy to identify additional sites for beneficial reuse of ash of the additional 70,000 tons of ash from Weatherspoon. This issue raises cost questions relevant to the DEC general rate case pending in Docket No. E-7, Sub 1146, and will be addressed in further detail in that case. Nonetheless, the Commission agrees with witnesses Garrett and Moore and DEP witness Kerin that Duke Energy should continue to make commercially reasonable efforts to identify additional sites for cost-effective beneficial reuse of ash in order to reduce closure costs for customers.

The Commission notes that DEP is not required to submit proposed closure plans for the impoundments at Roxboro and Mayo to DEQ for review and approval pursuant to G.S. 130A-309.214(a)(2) and (3). Therefore a prudence review of the Mayo and Roxboro closure plans would be premature at this time. As such, the Commission does not take any position with regard to the closure plans at those facilities at this time, since the current plans are preliminary in nature and have not yet been approved by the appropriate environmental regulatory agencies.

EVIDENCE IN SUPPORT OF FINDINGS OF FACT AND CONCLUSIONS NOS. 41-49

The evidence for these Findings of Fact is found in the testimony and exhibits of DEP witnesses Fountain, Bateman, McGee, Kerin, Wright, DeMay, and Wells; Public Staff witnesses Garrett, Moore, Lucas, and Maness; Sierra Club witness Quarles; CUCA witness O'Donnell; and Attorney General witness Witliff.

DEP DIRECT TESTIMONY

In their direct testimony, DEP witnesses stated that the coal ash costs included in the Company's rate request were incurred to comply with new laws and regulations. Specifically, ash basins are being closed pursuant to the United States Environmental Protection Agency (EPA) "Hazardous and Solid Waste Management System - Disposal of Coal Combustion Residuals From Electric Utilities - Final Rule" published in the Federal Register Vol. 80, No. 74, on April 17, 2015 (CCR Rule); the North Carolina Coal Ash Management Act (CAMA), Session Law 2014-122, and subsequent amending legislation; the Mountain Energy Act, Session Law 2015-110; and the Drinking Water Protection/Coal Ash Cleanup Act, Session Law 2016-95.

DEP North Carolina president Fountain summarized the Company's request for a five-year amortization with return to recover the costs of ash basin closure and compliance from January 1, 2015, to August 31, 2017. He also summarized the Company's request for an additional annual rate recovery for anticipated ongoing expenses related to coal ash closures and compliance. (T 6, pp 41-42) In her direct testimony, DEP witness Bateman explained the amounts in the DEP request:

> The total system spend on coal ash pond closure costs during this period for DE Progress is $482.7 million ($98.7 million in 2015, $212.7 million in 2016, and $171.3 million in the 2017 projected period). After applying allocations factors, netting with the cost of removal and incorporating the return on the deferred costs, the expected deferred balance as of August 31, 2017, on a North Carolina retail basis is $260.3 million. Over the 5-year amortization period, the annual amortization expense is $52.1 million. When added together with the net of tax return on the unamortized balance of $14.4 million, the total revenue requirement requested in this case for deferred coal ash pond closure costs is $66.5 million.

(T 6, p 123)

In supplemental testimony, witness Bateman adjusted the dollar amounts to reflect actual experience through August 31, 2017, resulting in an annual revenue requirement for deferred coal ash costs of $60.1 million. She indicated that of this amount, a portion would be deducted from rate case recovery if allowed to be recovered through the annual fuel rider:

> 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. While these amounts are included in this request, we believe these costs are more appropriately recovered through the annual fuel rider as discussed by Witness McGee. If the Commission approves the fuel rider treatment requested by Witness McGee, we would remove $15.1 million from the deferred balance in this adjustment.

(Id.)

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

> The expected ongoing level of O&M is based on the Company's actual spend on coal ash during the test period, which was $212.7 million on a system basis, or $129.1 million on a North Carolina retail basis. …. The Company is also requesting permission to establish a regulatory asset/liability and defer to this account the North Carolina retail portion of annual costs over or under the amount established in this proceeding. …. In addition, since the amortization proposed in Adjustment 18 only includes deferred costs through August 31, 2017, the Company requests to defer to the regulatory asset the coal ash spend incurred after that date, but before new rates from this proceeding are effective.

(T 6, p 124)

DEP witness Wright testified that costs associated with environmental compliance are proper to recover in rates. (T 13, p 354) He noted that the DEP coal plants have been used and useful in providing electric service, thus ash disposal costs associated with the plants should receive a return on the deferred balance. (T 13, p 355) As with other Company witnesses, he distinguished fines and penalties as costs that are appropriately excluded from rate recovery. (T 13, p 361) According to witness Wright, the coal ash costs for which the Company seeks recovery in the present case are related to new coal ash disposal regulations, with the exception of a small amount approved in prior cases for recovery as a "cost of removal portion of [DEP's] depreciation rates." (T 13, pp 368-69)

Witness Wright opined that "the Company historically has complied with all coal ash disposal regulations…." (T 13, p 375) He submitted that the coal ash costs in the present case are a "used and useful" utility cost, proper for inclusion in rate base. (Id.) Witness Wright maintained that the DEP coal ash costs should be deemed prudently incurred, and allowed to be recovered through an amortization with a return, similar to what the Public Staff recommended and the Commission approved in the 2016 Dominion North Carolina Power (DNCP) rate case (Docket No. E-22, Sub 532). (T 13, pp 378-79)

Most of the details of DEP's coal ash expenditures were described by Company witness Kerin. He stated that DEP was seeking recovery of CCR compliance costs, and that "[s]ince the 1920s, DE Progress has disposed of CCRs in compliance with then current regulations and industry practice." (T 16, p 103) He noted that fines and penalties related to coal ash management were excluded from the Company's rate request. (T 16, p 105)

Witness Kerin described the Company's coal-fired generation resources, the history of its ash handling, and the history of applicable regulations for coal ash management. He generally discussed the requirements of the CCR Rule, CAMA, consent or settlement agreements, and orders affecting closure of ash basins and other aspects of CCR management. (See T 16, pp 103-41) His exhibits showed, among other things, the amount of ash and history of disposal for each plant, initial closure plans for ash basins, a breakdown of expenditures in 2015-2016 for coal ash compliance at each plant site, and a plant-by-plant summary of ash management cash flows for Asset Retirement Obligation (ARO) purposes. Witness Kerin testified that the coal ash costs submitted for recovery in the present case were prudent and reasonable.

INTERVENOR TESTIMONY

Sierra Club witness Quarles testified that DEP's plans for cap-in-place closure of the ash basins at the Mayo and Roxboro plants would result in continuing contamination of down-gradient groundwater. He opined that the Company's closure plans for those two plants would violate the federal CCR Rule by not sufficiently protecting groundwater from migration of coal ash constituents. Witness Quarles requested that the Commission make findings to that effect. (T 13, pp 134-36)

CUCA witness O'Donnell maintained that CAMA was the direct result of Duke Energy mismanagement that caused the Dan River spill, and therefore costs resulting from CAMA should be excluded from rates. He cited Duke Energy's guilty pleas for criminal violations of the Clean Water Act as evidence of mismanagement. However, he stated that coal ash cleanup costs resulting from the CCR Rule were incurred in the "normal course of business" and therefore should be recovered in rates. (T 15, p 151)

Witness O'Donnell then estimated the amount of CAMA-based coal ash cleanup costs, over and above the costs to comply with the CCR Rule, by comparing the coal ash AROs of DEP and DEC to other electric utilities across the country that are not subject to CAMA-type cleanup requirements. He further refined that analysis by calculating the coal ash ARO cost per megawatt hour (MWh) of coal generation. His analysis showed that DEP has almost five times the coal ash ARO cleanup cost per MWh of generation as the average for "neighboring" utilities in nearby states. Witness O'Donnell noted that the current EPA is reconsidering the CCR Rule, so there is a possibility that costs to comply with the CCR Rule may be further reduced or even eliminated. (T 15, pp 152-59)

Witness O'Donnell recommended that the Commission disallow 75% of the coal ash costs submitted for recovery in the present case. He observed that this would still leave North Carolina customers paying more for coal ash disposal than customers in neighboring states. He also requested that coal ash costs allowed into rates be listed as a separate line item on customers' bills if his recommended coal ash disallowance is not adopted by the Commission. (T 15, pp 159-61)

Attorney General witness Witliff testified that while environmental compliance costs are normally appropriate for recovery in rates, the Company's imprudent coal ash management justified a disallowance of costs. (T 15, pp 25-27)

Witness Witliff based his conclusion of imprudence on several DEP actions or omissions. In particular, he maintained that DEP was unreasonably slow "to address seepage from the coal ash and scrubber sludge ponds at its eight coal-fired power stations." (T 15, p 30) He observed that in an August 1996 agreement with its insurance carriers, the Company acknowledged its legal exposure for pollution from its ash basins. (Id.) Dam safety inspections raised concerns about leaks and seeps in the 1990s, and for the Asheville plant, seepage concerns were identified by engineering consultants in 1981 correspondence and a 1964 report to DEP's predecessor company.

(T 15, pp 30-31) Witness Witliff stated that instead of acting responsibly, DEP channeled seepage "away from the [ash] impoundments and into waters of the United States via unpermitted discharge points." (T 15, p 32)

Witness Witliff noted that after the December 2008 rupture of an ash basin dike at the Tennessee Valley Authority's (TVA) Kingston Fossil Plant, the Commission asked for a status report from utilities under its jurisdiction. He testified that the Company studied the root causes of the TVA disaster and determined that its own plants were not at risk for those problems. He was critical of this approach as being too narrow, as the Company only looked at dam integrity and not at impoundments as a whole, including the integrity of the bottoms of the ash basins. (T 15, pp 36-40)

Witness Witliff posited that the Company's "criminal and civil negligence in managing its coal combustion residuals impoundments," including unpermitted discharges of coal ash wastewater to surface waters and contamination of groundwater, led to CAMA closure requirements that were more stringent than the CCR Rule. (T 15, p 55) He concluded that DEP's imprudence resulted in remediation and closure costs far greater than if the Company had not committed criminal negligence as evidenced by the federal guilty pleas. (T 15, p 58)

Witness Witliff did not recommend a specific dollar amount for disallowance. However, he did state that the "high priority" closure status for the Asheville and Sutton plants, which required expensive schedule acceleration, increased closure costs by about 72%. (T 15, p 52) Witness Witliff based this estimate on DEP witness Kerin's Exhibit 11. He identified $223,834,746 of closure costs for those two DEP plants alone (out of total coal ash ARO expenditures during 2015 and 2016 of $311,419,788) as being due to CAMA-based accelerated schedules. (Id.) Thus the Attorney General's position is similar to that of CUCA, arguing that the amount of coal ash costs due to CAMA, over and above the costs that would be incurred under the CCR Rule without CAMA, represent imprudence. Further, the Attorney General and CUCA contend that the amount of such imprudent costs is approximately 72-75% of the coal ash ARO expenditures incurred to date.

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. The disallowances recommended by witnesses Garrett and Moore are discussed separately in Finding of Fact 30-40, and the related Evidence and Conclusions section of this Order.

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. 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. (T 18, pp 270-71)

However, witness Lucas encountered “complicating factors” that led him to modify his preferred regulatory treatment. (T 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 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. (T 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. (T 18, p 281) Thus, the regulatory treatment of those costs is not in dispute. Disallowances recommended by Garrett and Moore are discussed elsewhere in this Order. 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) 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. (T 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 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. (T 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 National Pollutant Discharge Elimination System (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. (T 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. (T 18, pp 289-90)

Witness Maness proposed seven adjustments with respect to coal ash costs. (T 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. (T 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. (T 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. (T 18, p 307)

Witness Maness recommended three major[7] adjustments to the amount of coal ash management costs subject to deferral. (T 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 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 ash processing at the Asheville plant. This amount was reduced to approximately $29 million in Public Staff supplemental testimony. (T 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. (T 18, p 303) For all the foregoing adjustments, witness Maness was implementing, for accounting purposes, the recommendations sponsored by other Public Staff witnesses.

[7] An additional adjustment recommended by witness Lucas for disallowance of $88,000 of litigation expenses is reflected in Public Staff witness Peedin's Exhibit 1, Schedule 3-1(n). See also Maness Late-Filed Exhibit.

For the “equitable sharing” adjustment, witness Maness provided the substantive support for the recommendation, in addition to the support provided by witness Lucas. (T 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. (T 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. (T 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.

In terms of legal support for his recommendation, witness Maness noted that in State ex rel. Utilities Com. v. Thornburg, 325 N.C. 463 (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). (T 18, pp 310-13)

Witness Maness distinguished 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. (T 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. (T 18, pp 316-18)

DEP REBUTTAL AND SUPPLEMENTAL TESTIMONY

DEP witness Bateman filed supplemental testimony on September 15, 2017, to update several items in the rate request to August 31, 2017, and to make other adjustments. Items comprising the rate request were further adjusted in the Stipulation between DEP and the Public Staff, and corresponding supplemental testimony filed by those parties. These updates and proposed settlement terms resulted in changes to the initially filed position of the parties with regard to coal ash costs. The final differences between DEP and the Public Staff regarding recovery in rates of coal ash costs are shown on the December 22, 2017, Maness Late-Filed Exhibit.

DEP witness Fountain provided an overview of the Company's rebuttal case, including a summary of the DEP response on coal ash cost recovery issues. He stated, "The expenses [to manage and close coal ash basins] we have included in this rate request represent costs incurred from compliance with state and federal laws and regulations…." (T 6, p 69)

Witness Kerin's rebuttal primarily addressed the position of Public Staff witnesses Garrett and Moore, which is discussed elsewhere in this Order. However he also asserted that CUCA witness O'Donnell's recommended disallowance of 75% of coal ash ARO amounts was based on an inadequate comparison with coal ash AROs for other utilities. In particular, witness Kerin listed numerous factors affecting such AROs, which were not analyzed by witness O'Donnell and therefore in his opinion reflect a weakness in witness O'Donnell's analysis and recommendation.

Witness Bateman accepted two coal ash-related adjustments that were recommended by Public Staff witness Maness. The first is the addition of a return on the deferred balance of coal ash costs through the date of expected new rates in this proceeding. The second is the calculation of the return using a mid-month convention. (T 6, p 143)

Witness Bateman opposed the Public Staff's recommendation to remove from the rate request an estimated amount for ongoing environmental costs (the "run rate"). She noted that one reason offered by witness Maness was that the run rate would make future equitable sharing of coal ash costs much harder to achieve, and that the Company opposed any sharing of such costs for the reasons stated by DEP witness Wright. Witness Bateman added that coal ash basin closure costs would be recurring in the future, and that rates should reflect these costs as a "normal level of ongoing costs." She noted that closure costs previously had been treated as a cost of removal and allowed in rates to recover estimated future spending. Lastly, witness Bateman argued that the Public Staff's proposal to allow deferral of future coal ash costs to a regulatory asset, with regulatory treatment for those costs to be decided in future rate cases would create cash flow shortfalls and impact the Company's credit metrics. (T 6, pp 144-45)

DEP witness Wright, in rebuttal testimony, took issue with the Public Staff's equitable sharing recommendation. (T 20, pp 128-29) He characterized witness Lucas' position as choosing to assign 50% of the coal ash costs to DEP just for "simplicity." (T 20, p 131) He argued that Mr. Lucas' proposal was not a correct substitute for identifying imprudence. He then characterized witness Lucas' position as disallowing environmental "compliance" costs on the theory that DEP was a "bad actor." (T 20, p

132) Witness Wright further criticized witness Lucas for relying on environmental issues "that may have happened in the past or could occur in the future," rather than known violations. (T 20, pp 132-33)

Witness Wright opposed equitable sharing for what he viewed as reasonable and prudent costs to comply with new environmental standards. (T 20, pp 133-34) He testified that witness Lucas was inconsistent in citing DEP's environmental litigation to support the idea of Company culpability, when the Public Staff had not opposed full recovery of coal ash costs in the 2016 DNCP rate case. He argued that DEP and DNCP are "similarly situated," noting that a federal court had found DNCP's parent company in violation of the federal Clean Water Act. (T 20, pp 135-37)

Witness Wright rejected the comparison of regulatory treatment for coal ash costs to that of abandoned nuclear plant costs. He argued that the abandoned nuclear plants were never used and useful, but that CCR repositories were used and useful and therefore coal ash disposal costs were used and useful, making it appropriate to include in rate of return on those costs. Likewise, he distinguished manufactured gas plant costs because of a "timing difference" between use of those facilities and their environmental clean up costs, which he argued was different from the timing with coal ash costs. He also stated that DEP or its predecessors had always owned the coal ash basins, but the manufactured gas plants had changed ownership before clean up costs were incurred by the regulated gas utilities. (T 20, pp 137-38, 140-44)

Witness Wright characterized witness Maness' position as arguing that an equitable sharing of coal ash costs was appropriate just because the costs were extremely large. He argued this approach was outside any regulatory policy or law and would drive up the perceived risk of utilities. (T 20, pp 144-45)

Witness Wright then stated his understanding and criticism of some of the reasons given by witness Lucas for an equitable sharing. He surmised that witness Lucas' position was that Duke Energy "caused or substantially caused" both CAMA and the CCR Rule. He argued that there was no basis to conclude the Dan River accident led to modifications in the final CCR Rule, nor any reason to conclude that Dan River resulted in a stricter CAMA than otherwise would have occurred. He pointed out that other states have enacted state-specific coal ash laws or rules just as North Carolina did. He further argued that North Carolina's 2L groundwater rule[8] would have required compliance costs in any event. He maintained that the CCR Rule and CAMA were not meant to be punitive, so costs incurred under those requirements are recoverable. (T 20, pp 145-53)

Witness Wright disagreed with witness Lucas' recommended disallowance of $88,000 in Sutton plant litigation costs. He observed that fines, penalties, and fees related to Dan River were appropriately excluded by DEC from its rate request because that case involved an admission of guilt. He did not oppose exclusion of legal fees where DEP has admitted liability or been adjudicated as liable. However, he characterized witness Lucas' approach as excluding all costs of defending lawsuits, regardless of liability. He said that witness Lucas in effect advocated that legal defense costs were <u>per se</u> imprudent, which was equivalent to arguing the Company should never defend itself or settle cases. He distinguished a case relied upon by witness Lucas, (Glendale Water, 317 N.C. 26 (1986)) as being different in nature, and involving avoidable legal fees, whereas the $88,000 of DEP legal fees were not avoidable. Witness Wright also testified that Mr. Lucas should not have concluded that settlements and consent orders entered by DEP were equivalent to admissions of guilt. He noted that DEP did not admit any liability in its settlements of environmental lawsuits over coal ash contamination, and that settlements should be encouraged as a matter of policy. (T 20, pp 153-59)

Witness Wright indicated that witness Lucas was unreasonable in saying shareholders should bear remediation costs above what is necessary to comply with CAMA at the Mayo and Roxboro plants (if any such costs are established by pending litigation), while at the same time expecting DEP to be in full compliance with groundwater standards. He also disputed the recommendation from witness Lucas that $6.7 million in costs for groundwater extraction wells and treatment should be disallowed. He argued that these costs should be recoverable in the absence of any proof that they resulted from imprudence. He contended there is no evidence that the 2L groundwater standards are comparable to strict liability requirements. Witness Wright posited that if the Company had taken actions to prevent coal ash contamination in the undefined past, beyond legal requirements and industry practices, other parties would likely have argued that the costs were "gold plating." He maintained the

[8] Title 15A, North Carolina Administrative Code, subchapter 2L.

Company took a reasonable course of action based on what it knew at the time. (T 20, pp 15-64)

Witness Wright also argued against witness Maness' recommendation of provisional cost recovery. Witness Wright stated that provisional rates appeared to be retroactive ratemaking and the utility should not be subject to hindsight review. (T 20, pp 165-66)

Finally, witness Wright disagreed with the positions of Attorney General witness Witliff and CUCA witness O'Donnell. He maintained that witness Witliff's argument that DEP committed "bad acts," caused CAMA, and therefore should be punished, was flawed. Witness Wright stated that any disallowance should be based on evidence of imprudence, and there must be a causal link between the imprudence and the costs to be disallowed. He noted that witness O'Donnell did not make any attempt to quantify CCR Rule compliance costs, so there was no mathematical basis to exclude CAMA costs that are incrementally above CCR Rule costs. (T 20, pp 167-69)

DEP witness Wells testified in rebuttal that DEP had taken appropriate steps to manage groundwater and seeps at its ash basins, contrary to witness Lucas' negative characterization of the Company's environmental compliance. (T 21, p 62) He noted that witness Lucas had incorrectly identified over 2,000 NPDES permit violations over the past ten years, whereas there were no more than 20 such violations at all plants except Mayo, which had about 150 violations. (T 21, p 64) He pointed out that witness Lucas had incorrectly included groundwater exceedances in his count of NPDES permit violations. (T 21, pp 64-65) (This confusion was clarified by Mr. Lucas' supplemental testimony and Revised Lucas Exhibit 5, where he identified 455 NPDES permit violations that were not groundwater exceedances.)

Witness Wells maintained that the large number of groundwater exceedances shown by witness Lucas in Lucas Exhibit 6 was misleading in three ways. (T 21, p 66) First, groundwater requirements evolved over time, the Company "has taken every action required by DEQ pursuant to the 2L groundwater rules, and later the Coal Ash Management Act of 2014 ("CAMA"), to address groundwater impacts as they have been identified." (Id.) Second, unlined ash basins were the primary technology used to dispose of coal ash in the years when DEP built its ash basins. (T 21, p 67) Third, the 2L groundwater rules did not require monitoring of groundwater. (T 21, p 68) He stated that if DEP had used lined landfills initially, or removed ash from unlined basins when groundwater concerns first arose, as "Mr. Lucas seems to suggest," then the Company would have been using unproven technology without regard to cost and without legal obligation. (T 21, pp 69-70)

Witness Wells disputed the testimony of witness Lucas that DEP did not engage in comprehensive groundwater monitoring and remediation until the threat of litigation, the Dan River spill, and CAMA occurred. He noted that the Company began groundwater monitoring at its Sutton plant in 1984, with the addition of Weatherspoon in 1990, Roxboro in 1987, and voluntary monitoring at other plants in 2006. He quoted from depositions of DEQ personnel to the effect that DEP had cooperated with compliance requirements. (T 21, pp 70-73)

Witness Wells further testified that state groundwater regulations and DEQ practices are intended to achieve corrective action, not enforcement, and therefore are not meant to be used to deny cost recovery in regulatory proceedings. (T 21, pp 73-74) He argued that witness Lucas conflated the concepts of groundwater exceedances and groundwater violations. (T 21, p 74) Witness Wells denied that groundwater exceedances at the Sutton plant were the result of mismanagement. (T 21, p 76-77) Instead, he stated that the extraction and treatment work would have been required of DEP "under the normal course as part of groundwater corrective action under the CCR Rule and CAMA even without the NOV [notice of violation from DEQ]." (Id.)

Witness Wells said that witness Lucas suggested DEP was imprudent based on the amount of litigation regarding the ash basins. (T 21, pp 77-79) He attributed the litigation to non-governmental organizations, and stated that the "volume of litigation on its own" did not indicate imprudence. Witness Wells also testified that, according to witness Lucas, any exceedance or violation, no matter how minor or dated, should lead to disallowance of costs. (T 21, pp 79-80) He argued that the corrective action provisions in the 2L rules show that exceedances were expected from facilities that were built before liners were required, and that such exceedances are to be addressed in a measured manner rather than classified as mismanagement. (Id.)

Witness Wells discussed seeps at length. (T 21, pp 81-85) He noted that seeps are the movement of liquid through earthen dams, and that some seeps exhibit low or no flow volume and may be transient. He stated that DEP's engineered seeps that discharge to surface waters were included in its 2014 NPDES permit applications. Witness Wells testified that DEQ did not consider seeps to be a priority in earlier years.

He stated that closure of ash basins would be one way to correct seeps, but that closure would not necessarily be required as a result of seeps. He stated that DEQ is "working on" how to address DEP's seeps, whether by including them in NPDES permits or "other means." He said that witness Lucas had implied that seeps would have led to basin closure, and he disagreed with that conclusion.

Witness Wells challenged the testimony of witness Lucas that DEP's failure to comply with environmental regulations was a contributing factor to the adoption of both the CCR Rule and CAMA. (T 21, pp 85-87) He stated that the EPA had engaged in two decades of study before issuing the proposed CCR Rule in 2010, and had identified groundwater damage from coal ash across the country to justify the CCR Rule, but had not identified damage from DEP other than two cases of surface water discharges that were resolved in the early 2000s.

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

<u>COMMISSION REVIEW OF EVIDENCE AND CONCLUSIONS</u>

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

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

Docket No. E-2, Sub 1103, Deferral Request

In Docket No. E-2, Sub 1103, DEP petitioned for an order allowing it to defer into a regulatory asset account its coal ash costs incurred between January 2015 and the date of its next base rate case. The Company was recording the costs as AROs because the costs were required to comply with state and federal laws. In its March 15, 2017, comments in the petition docket, 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.

Comments were also filed by CUCA, the Attorney General, Appalachian State University, the Cities of Concord and Kings Mountain, and the Sierra Club. 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 finds that the deferral request is reasonable and appropriate. As noted by the Public Staff, the costs for which DEP sought deferral meet the Commission's criteria for deferral for regulatory accounting purposes. 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.

Reasonableness of Costs: Legal Fees for Environmental Litigation

Witness Lucas recommended disallowance of $88,000 in test year litigation costs, along with exclusion of approximately $6.7 million for extraction and treatment of groundwater that is discussed later in the Evidence and Conclusions section. These costs were incurred in connection with environmental litigation involving the Sutton plant, where DEQ assessed a penalty for groundwater violations and SELC brought a citizen action suit under the Clean Water Act. Both cases were settled.

Settlement of litigation normally precludes a judgment of liability. This leaves a question of whether allegations of environmental violations had underlying merit. Witness Wright argued that allegations of environmental violations must be admitted by the Company or found in a judicial ruling before the associated litigation costs can be disallowed from rates.

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

Nonetheless, in the circumstances of the present case, the Commission finds that substantial evidence supports disallowance of the $88,000 adjustment for litigation costs and also the $6.7 million adjustment for extraction well costs. While the Company denied wrongdoing in the Sutton cases, and the settlements explicitly state there is no admission of wrongdoing, the Company's groundwater monitoring reports to DEQ for the Sutton plant show exceedances of 2L groundwater quality standards at or beyond the compliance boundaries for the Sutton plant. (Revised Lucas Exhibit 6) The Environmental Audit reports of third party experts hired by DEP show groundwater exceedances at Sutton, due to the ash basins. (Public Staff Wright Rebuttal Cross-Examination Exhibit 2) Wording in the settlement agreement between DEP and DEQ identifies offsite groundwater impacts due to the ash basins. (Public Staff Wright

Rebuttal Cross-Examination Exhibit 7) The DEP federal criminal plea agreement notes offsite groundwater impacts. (Public Staff Wright Rebuttal Cross-Examination Exhibit 1) In weighing the competing evidence, the Commission finds overwhelming support for the DEQ and SELC claims against DEP with regard to the Sutton plant. Details of this evidence are discussed below. First, however, there is a legal question as to whether conclusive evidence of environmental violations justifies a disallowance of litigation costs and of remediation costs that are above what CAMA and the CCR Rule would have required in the absence of violations.

The Commission concludes that disallowance of such costs is legally proper. Mr. Lucas cites the Glendale Water case, State ex rel. Utilities Comm. v. Public Staff, 317 N.C. 26 (1986), where legal expenses incurred by a utility in defense of a penalty proceeding were excluded from rate recovery as a matter of law. (T Vol 18, p. 275) He quoted from the Glendale Water case as follows:

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

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

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

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

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

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

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

The evidence of violations at the Sutton plant is found in multiple sources, including sources validated by DEP. First, the Company is required to report to DEQ the results of samples from its groundwater monitoring wells at Sutton. As shown on Revised Lucas Exhibit 6, DEP has violated the regulatory limits for constituents listed in 2L and IMAC standards and federal maximum contaminant levels (MCL) at the Sutton plant 723 times.[9] Witness Lucas made clear that he was only counting violations, not exceedances that might be due to background levels of the constituents:

> Q. Let's turn to your Revised Exhibit 6 now. And there has been considerable discussion about the difference between an exceedance of 2L groundwater standards and a violation of 2L groundwater standards.
>
> Have you done an analysis here that shows that difference?
>
> A Yes. My Revised Lucas Number 6, I separate what were — separate between violations and exceedances, and I show that there were over 2,800 actual violations.
>
> Q. Can you tell us which line and column that is on this exhibit?
>
> A. Okay. On Revised Lucas Exhibit Number 6, second column from the right, down at the bottom, it's 2,857 violations.
>
> Q. And what is the data source for this?
>
> A. This is response to a Public Staff data request. The Company provided this data to us.

(T 19, p 44)

Second, the Joint Factual Statement signed by DEP as part of its plea agreement in the federal criminal case includes the following facts, as set out in Lucas Exhibit 9 (also in Public Staff Wright Rebuttal Exhibit 1):

> 185. DUKE ENERGY PROGRESS owns and operates the L. V. Sutton Steam Station ("SUTTON") in New Hanover County, North Carolina.

[9] There are 2,857 groundwater violations for all seven DEP coal plants in North Carolina.

SUTTON houses two coal ash basins, one constructed in 1971 and one constructed in 1984.

186. Located near SUTTON is the community of Flemington. Flemington's water supply has a history of water-quality problems. In 1978, an adjacent landfill, designated as a "Superfund" site, contaminated Flemington's drinking water and caused authorities to construct new wells.

187. Flemington's new wells are located near SUTTON's coal ash basins. They are located down-gradient from the SUTTON coal ash basins, meaning groundwater ultimately flows from the coal ash basins toward the Flemington wells.

188. DUKE ENERGY PROGRESS/Progress Energy Carolinas has monitored groundwater around SUTTON since 1990. Monitoring particularly focused on a boron plume emanating from the coal ash ponds.

189. From at least 2010 through 2013, the groundwater monitoring wells at SUTTON reported unnaturally elevated levels of some constituents, including manganese, boron, sulfate, and total dissolved solids.

190. Flemington's public utility also, tested its water quality. Those tests showed exceedances of barium, manganese, sodium, and sulfate in 2013.

191. In June and July 2013, Flemington's public utility concluded that boron from SUTTON's ash ponds was entering its water supply. Tests of water from various wells at and near SUTTON from that period showed elevated levels of boron, iron, manganese, thallium, selenium, cadmium, and total dissolved solids.

192. In October 2013, DUKE ENERGY PROGRESS entered into an agreement with the - Cape Fear - Public Utility Authority - to share costs for extending a municipal water line to the Flemington community.

(Emphasis added.) Thus, as part of its federal plea agreement DEP admitted the existence of the boron plume emanating from its ash basins, and elevated levels of coal ash constituents in wells at or near the Sutton plant.

Third, the 2017 Environmental Audit report for the Sutton plant shows exceedances of the following constituents at or beyond the compliance boundary, as summarized in Lucas Exhibit 7: arsenic, boron, chloride, chromium (VI), cobalt, iron, manganese, pH, TDS, and vanadium. The Environmental Audits were conducted by independent consultants, reporting to Duke Energy and the Court Appointed Monitor, as a condition of the Company's federal probation. They are excerpted in Public Staff Wright Rebuttal Exhibit 2, and can be found online in links at the webpage https://www.duke-energy.com/our-company/environment/compliance-and-reporting/environmental-compliance-plans. The same Lucas exhibit and Duke website contain Duke Energy's response to the 2017 Sutton plant Environmental Audit report. In that response, Duke Energy does not contest the finding of exceedances. It does include in its "Actions to Resolve" a commitment to Corrective Action Plans.

Fourth, the wording in the settlement agreement between DEP and DEQ makes clear the nature of violations, despite the inclusion of the statement that DEP admitted no wrongdoing. The DEQ proceeding was initiated by a March 10, 2015, letter along with findings and a penalty assessment. (Public Staff Wright Cross-Examination Exhibit No. 6.) DEQ alleged violations of G.S. 143-215.1 and the groundwater quality standards of 15A NCAC 2L.0106 in the 2010-2013 sampling period as follows:

- Arsenic exceedances for 365 continuous days
- Boron exceedances for 1,822 continuous days
- Iron exceedances for 730 continuous days
- Manganese exceedances for 730 continuous days

- Selenium exceedances for 729 continuous days
- Thallium exceedances for 1,668 continuous days
- Boron exceedances for 1,822 continuous days
- Total Dissolved Solids exceedances for 728 continuous days

DEQ assessed a civil penalty of more than $25.1 million for these violations.

The DEQ penalty assessment was challenged by DEP, and the case was settled on September 29, 2015. (Public Staff Wright Cross-Examination Exhibit No. 7.) Boilerplate "Legal Provisions" in the settlement state that "the Parties to this Agreement make no admission of liability, violation, or wrongdoing whatsoever…." Duke Energy agreed to pay DEQ the sum of $7 million to settle all claims of groundwater exceedances at Duke Energy's North Carolina facilities. Most significantly, the Company's obligations under the settlement plainly reveal extraordinary action necessary to mitigate the impacts of contaminated groundwater coming from DEP ash basins and impacting property off the DEP plant sites:

II. DUKE ENERGY'S OBLIGATIONS

A. Consistent with 15A NCAC 2L .0106 Duke Energy shall implement accelerated remediation at the Sutton Plant on the following terms and conditions:

(1) Duke Energy will commence installation of extraction wells on the eastern portion of the Sutton Plant property <u>where data show constituents associated with the ash basins at concentrations over the 2L standards ("Constituents of Interest") have migrated off site</u>.

(2) Extraction wells will be used to pump the groundwater <u>to arrest the off-site extent of the migration</u>. The pumped groundwater will be

treated as needed to meet standards and returned either to the ash basin or the discharge canal.

(3) This extraction and treatment system will be installed as soon as practicable following receipt of all permits and approvals from DEQ, the issuance of which will occur as soon as practicable. This accelerated groundwater remediation is in addition to and shall be performed concurrent with the coal ash impoundment closure obligations set forth in CAMA.

(4) The extraction wells shall remain operational until such time as Duke Energy demonstrates through sampling, analysis, and appropriate modeling, and subject to DEQ's written concurrence, that off-property constituents of interest have been remediated to 2L Standards and there is no reasonable potential for future off-site migration.

(5) As part of accelerated remediation, DEQ agrees that dry ash can be removed from the head of the ash basins under a construction storm water permit and shall expedite such construction storm water permit in order for Duke Energy to commence the removal of ash which is the source of the constituents of interest from the Sutton Plant. DEQ will issue construction storm water permits for Sutton plant within 10 days of receiving Duke Energy's complete application. Only dry ash from the head of the ash basins will be removed with no impact to wastewater treatment or water levels in the basins. DEQ shall use its best efforts to complete the process of the issuance of the NPDES permit modification at the Sutton Plant to allow for the removal of water and ash beyond the areas covered under the construction storm water permit from the Sutton Plant.

B. Consistent with 15A NCAC 2L .0106 Duke Energy shall implement accelerated remediation at the Asheville Plant, Belews Creek Plant, and H.F. Lee Plant, which are the only three other Duke Energy facilities that demonstrated offsite groundwater impacts in isolated areas that are not impacting private wells in the Comprehensive Site Assessments conducted pursuant to CAMA. Such accelerated remediation shall be tailored to each facility's unique characteristics.

(Emphasis added.) The purpose of the extraction wells is to arrest the offsite spread of coal ash constituents, in exceedance of 2L standards, coming from DEP ash basins. DEP signed these terms; there can be no doubt the Company had committed groundwater violations at its Sutton plant, as well as the Asheville and H.F. Lee plants mentioned in part B above.

This evidence of groundwater violations is further bolstered by the DEQ press release following the settlement. (Public Staff Wright Rebuttal Cross-Examination Exhibit No. 8.) According to DEQ, the settlement "holds Duke Energy accountable for past groundwater contamination." The press release noted that Duke Energy would be required to "clean up all environmental damage caused by years of improper coal ash storage."

Against this evidence, the Commission gives little weight to the argument of witness Wright that legal fees should only be disallowed if there is an admission of guilt or an adjudication of guilt. (T 21, pp 28-29, 31) With regard to the question of whether there were violations in fact at the Sutton plant, he deferred to DEP witness Wells; yet at the same time witness Wright opposed exclusion of the legal fees. In fact, witness Wright admitted that he did zero review of the environmental violations. If witness Wright was unsure whether there were violations in fact, he had no basis for supporting or opposing exclusion of legal fees related to violations at Sutton. Witness Wells argued that the exceedances at Sutton were not the result of mismanagement (T 21, pp 76, 94), but he never testified that there were no violations at the Sutton plant. He did state the Company found groundwater exceedances of boron at the Sutton compliance boundary as early as 2006 (T 21, p 150), and that absent the exceedances at Sutton, H.F. Lee, and Asheville, the Company would not have been required to install extraction wells at those plants (T 21, p 176).

In sum, the Commission finds overwhelming evidence of environmental violations in connection with the Sutton litigation. The Commission rejects the position that legal fees may only be excluded from rate recovery when there is an admission or adjudication of guilt. Otherwise there would be “moral hazard”: the Company would have an incentive to settle all cases, regardless of settlement cost, because it could be assured of cost recovery in rates even when the evidence of violations was clear. The Commission concludes that a decision on exclusion of such costs should be based on all the evidence in each case, which in the present case demonstrates environmental violations.

DEP witness Wright correctly pointed out that the amount of money at issue on litigation fees for cases of coal ash environmental violations is remarkably small in the scale of the total rate request, and yet the principle involved is significant. As Public Staff witness Lucas recommended, the disallowance of litigation costs should extend to outside legal fees, internal labor, and third party assistance such as consultants and expert witnesses retained for the litigation, in cases where either the judgments or the underlying facts show that the Company violated environmental laws or regulations. Future developments in pending legal matters may establish more environmental violations from the past, and thus the issue of whether to allow or exclude additional litigation costs could be relevant in future rate cases, and the costs may be more substantial.

In accord with the Glendale Water case, the Commission concludes that exclusion of such costs is somewhat fact-specific: it may be reasonable to allow recovery of litigation costs in the unlikely event that there is litigation over isolated minor violations. However, as in the present case, identifiable litigation costs for extensive or severe violations are properly excluded from rates.

Reasonableness of Costs:
Expenditures for Extraction Wells and Groundwater Treatment

The Commission's findings and conclusions on the exclusion of $88,000 of legal fees are also pertinent to the approximately $6.7 million in costs for extraction wells and treatment at the Sutton, H.F. Lee, and Asheville plants. The purpose of the extraction wells is to arrest the offsite migration of constituents from DEP's ash basins. See Public Staff Wright Cross-Examination Exhibit No. 7. As stated in the settlement that DEP signed, "This accelerated groundwater remediation is in addition to and shall be performed concurrent with the coal ash impoundment closure obligations set forth in CAMA." (Id.; emphasis added) Public Staff witness Lucas recommended disallowance of the extraction well costs "because they are costs due to environmental violations, and they exceed the amount of costs required for CAMA compliance in the absence of environmental violations." (T 18, pp 279-280) The Commission agrees. Where environmental violations increased specific costs of managing coal ash above what CAMA otherwise would have required, it would be unreasonable to allow those costs into rates.

Company witnesses Wright and Wells argued that the extraction wells were not "mismanagement" as claimed by witness Lucas. Witness Lucas made clear that he was not talking about "mismanagement" in the sense of traditional ratemaking prudence analysis, but rather the Company's failure to comply with laws:

> Q. Mr. Lucas, just on that last question, since we are there, do you know when the 2L groundwater standards were adopted in the state of North Carolina?
>
> A. 1979.
>
> Q. And did Duke Energy Progress and its predecessor company have an obligation to comply with those standards?
>
> A. Yes.
>
> Q. And was that obligation in effect without regard to whether there was any imprudence or negligence on their part?
>
> A. Yeah. The two standards don't talk about negligence and prudence. They just say, here are the standards, and everyone must obey them.

(T 19, pp 41-42; see also T 18, p 272) In effect, the Company witnesses argued that disallowance is improper in the absence of a showing of imprudence, whereas the Public Staff argued that a violation of law properly supports a disallowance regardless of whether specific Company decisions, acts, or omissions can be identified as imprudent based on what the Company knew at the time of the decisions, acts, or omissions.

The Commission concludes that it is not necessary in the present case to decide if every utility violation of a law or regulation requires exclusion of remedial costs. For instance, payment of tort damages for vehicle accidents caused by Company personnel might be treated as a normal cost of business. However, that is not the case presently before the Commission. Environmental violations resulting from coal ash are a major public policy problem, from the TVA disaster, to the Dan River storm pipe collapse, to the less dramatic, but broadly damaging, impact of groundwater contamination. The

EPA responded with the CCR Rule. The North Carolina General Assembly responded with CAMA. DEQ responded with enforcement actions against all Duke Energy plants in North Carolina. South Carolina took action resulting in DEP's agreement to excavate ash from the Robinson plant and environmental groups joined DEQ's state enforcement actions and brought citizen action lawsuits. The costs to address coal ash are estimated at $4.5 billion for Duke Energy in the Carolinas.[10] Groundwater contamination has been reported at every DEP coal plant in the Carolinas, over a period of years. In these circumstances, the Commission finds and concludes it would be unreasonable to charge ratepayers for costs of environmental violations, over and above the costs required to comply with CAMA in the absence of environmental violations. The specific costs identified in this case are the extraction well and groundwater treatment costs of $6.7 million that should be disallowed. It is appropriate to hold the Company responsible for those costs because the costs are the direct result of violations of laws and regulations; such costs should not be deemed a normal cost of providing electric service.

<u>Equitable Sharing Proposal</u>

Public Staff witnesses Lucas and Maness recommended an "equitable sharing" of coal ash costs that are not otherwise disallowed. Specifically, witness Maness proposed a 50%-50% sharing between ratepayers and shareholders for coal ash costs submitted for recovery in DEP's rate request, incurred between January 1, 2015, and

[10] The December 30, 2016, DEC and DEP Petition for an Accounting Order in Docket Nos. E-2, Sub 1103, and E-7, Sub 1110, states in part: "the total value of the Companies' AROs recorded as of September 30, 2016 related to coal ash basin closure costs to date is approximately $4.5 billion." Of that amount, $2.4 billion is for DEP.

August 31, 2017. He calculated that a 26-year amortization at the proposed settlement cost of capital would produce a 50%-50% sharing if there were no return allowed on the unamortized balance.

In contrast, DEP proposed a five-year amortization of all its requested coal ash costs incurred between January 1, 2015, and August 31, 2017, with a return at the proposed settlement cost of capital on the unamortized balance. The difference between the updated positions of the Public Staff and DEP is shown in Maness Late-Filed Exhibit. For presently deferred coal ash costs, the annual revenue requirement proposed by the Public Staff for coal ash costs is approximately $6.1 million for 26 years. In contrast, the annual revenue requirement proposed by DEP for presently deferred coal ash costs is approximately $60.1 million for five years. These amounts do not include costs for future coal ash expenditures, which are discussed later.

As noted in discussion above, Company witnesses in direct testimony maintained that the coal ash costs included in the present rate request were prudent and reasonable environmental compliance costs. Their testimony identified new legal obligations under the CCR Rule and CAMA, giving rise to AROs for ash basin closures and related activities. They requested full rate recovery for the deferred coal ash costs. In rebuttal and in cross-examination, the Company challenged the equitable sharing proposal on a number of fronts, discussed below.

The Public Staff testified to two general reasons for an equitable sharing. First, as noted by witness Maness, past Commission decisions and a ruling of the Supreme Court of North Carolina provide support for equitable sharing in unusual circumstances.

(T 18, pp 309-313) In his opinion, the nature and magnitude of coal ash costs make them appropriate for equitable sharing.

Second, as stated by witness Lucas, "An equitable sharing is particularly appropriate in light of the extent of the Company's failure to prevent environmental contamination from its coal ash impoundments, in violation of state and federal laws." (T 18, p 282) He testified that some environmental violations "are not easily characterized as either plainly imprudent or plainly reasonable on DEP's part." (Id.)

Where violations are due to the Company's imprudence, the costs are unreasonable and should be totally excluded from rates. Where costs are entirely reasonable, they typically (but not always) would be included entirely in rates. These regulatory outcomes are based on G.S. 62-133(b). However, the law also allows for a middle ground – an equitable sharing – when otherwise prudent costs would be unreasonable or unjust to include in rates under G.S. 62-133(d). Because the middle ground of equitable sharing alters the normal regulatory framework of allowing prudent costs into rates, it should be applied only in unusual and compelling circumstances.

Witnesses Lucas and Maness have described unusual and compelling circumstances in the present case. First, there is no doubt that coal ash costs are extraordinary in both nature and amount. The Company in its April 19, 2017, Reply Comments in Docket No. E-2, Sub 1103, justified its deferral request for coal ash costs, in part, on the basis of "the extraordinary nature and uniqueness of the costs requested to be deferred (and the magnitude of the costs)." In its December 30, 2016, Petition for an Accounting Order in the same docket, the Company stated it had recorded AROs estimating coal ash compliance costs of $2.1 billion for DEP and $2.4 billion for DEC. Moreover, the nature of the costs is more analogous to cleanup costs for manufactured gas plants, for which there was equitable sharing, than anything else before the Commission. The coal ash has already been disposed of once by DEP; the new costs represent additional disposal costs for the same ash, without the benefit of any additional electricity being produced. In other circumstances, the enactment of new environmental requirements may justify full recovery of costs, but with DEP coal ash disposal, a significant portion of the costs result from the Company's failure to comply with pre-existing environmental regulations.

DEP maintains that its deferred coal ash costs have been incurred to comply with the CCR Rule and CAMA. The Commission finds this contention is true with respect to the costs for which the Public Staff has proposed equitable sharing. CAMA requires groundwater assessments, corrective action plans to remediate contamination risks, and closure of the ash basins. However, the Commission also finds that the CCR Rule and CAMA compliance costs incurred by DEP substantially substitute for costs that otherwise would have been incurred to remediate environmental violations caused by DEP. Corrective actions and closures of ash basins required by the CCR Rule and CAMA essentially duplicate the remediation efforts that would have been required pursuant to 2L regulations and other legal requirements.

As a matter of law, the duty to comply with G.S. 143-215.1, NPDES permit conditions, and the 2L groundwater regulations exists without regard to whether the Company was prudent or imprudent. DEP had a legal responsibility to prevent – not merely to respond to – groundwater and surface water contamination. To the extent

DEP's failure to meet its legal responsibility resulted in remediation costs, and either it is unclear whether the costs were the result of imprudence, or the cost is subsumed under general CAMA compliance costs and cannot be separately quantified, those costs should be equitably apportioned between ratepayers and shareholders.

The extent of environmental violations committed by DEP is revealed in Public Staff exhibits. There are deficiencies in dam safety that required repairs (Lucas Exhibits 3 and 4), NPDES permit violations in connection with discharges to surface waters (Lucas Exhibit 5), and unpermitted discharges to surface waters in violation of G.S. 143-215.1 (e.g., seeps admitted in the Joint Factual Statement from the federal criminal plea in Public Staff Wright Rebuttal Cross-Examination Exhibit 1, and identified in the Environmental Audit reports in Public Staff Wright Rebuttal Cross-Examination Exhibit 2, as well as noted in Lucas Exhibit 5). However, most significant among environmental violations are the groundwater violations at every DEP coal-fired plant in the Carolinas (Revised Lucas Exhibit 6, Lucas Exhibit 7, and the Environmental Audit reports in Public Staff Wright Rebuttal Cross-Examination Exhibit 2). The groundwater violations are extensive: 2,857 violations of groundwater quality standards across the North Carolina plants (Revised Lucas Exhibit 6), and arsenic violations at the Robinson plant in South Carolina (Public Staff Wright Rebuttal Cross-Examination Exhibit 2).

In addition, the Company admitted to 17 unpermitted engineered seeps (Public Staff Wells Cross-Examination Exhibit 5, response to Public Staff data request 27-24). While the total number of seeps exceeded 200 across the DEP and DEC plants in the State (<u>see</u> Lucas Exhibit 9), the engineered seeps are especially problematic. These are intentional acts by the Company, in complete disregard of the statutory permitting requirement in G.S. 143-215.1 and the federal Clean Water Act that are intended to protect North Carolina waters from pollution.

DEP's position that its coal ash costs were necessary to comply with the CCR Rule and CAMA misses an essential point. The Company's extensive environmental violations, occurring at all its plants across the Carolinas, would have required remediation at considerable expense even without the CCR Rule and CAMA. It would be inequitable and poor public policy to conclude that enactment of the CCR Rule and CAMA should shield DEP from cost responsibility for its violations. Certainly, there is no indication that the EPA or the General Assembly intended to shield the Company from this cost responsibility. Cost responsibility is appropriately a question left to the Commission, and the Commission concludes that the costs of remedying contamination flowing from DEP's ash basins should not be entirely the responsibility of ratepayers.

As Public Staff witness Lucas testified (see, e.g., T 18, p 339), most of the costs of remedying environmental violations, cannot be quantified independently of CAMA and CCR Rule compliance costs. The reason is that those remedial costs require speculation as to alternative scenarios that did not occur. Specifically:

(1) DEQ is still determining which of the existing unlawful DEP seeps or unlawful discharges will be allowed under new NPDES permits, and which will require remedial action under a Special Order by Consent;

(2) At least two lawsuits, involving existing contamination from ash basins and the appropriate closure methods at the Mayo and Roxboro plants,

are in active litigation, so the costs of remediation and closure are yet to be determined;

(3) Arguably, the costs of remediating groundwater contamination from ash basins should be netted against the costs of installing liners at the time the basins were constructed, but the costs of installing liners decades ago is too speculative to accurately quantify; and alternatively, the costs to retrofit existing basins or convert to dry ash disposal decades ago are also too speculative to accurately quantify; and

(4) The costs of remedying violations in response to citizen action and DEQ enforcement lawsuits if there had been no CCR Rule and CAMA is also too speculative. For example, CAMA ultimately required closure by excavation of coal ash at five of the seven DEP coal-fired plants in North Carolina. Whether judgments in the enforcement lawsuits would have also required closure by excavation, as opposed to less expensive methods such as cap in place, is too speculative to know.

What is known is that the extensive coal ash-related environmental violations documented in data reported to DEQ and in response to Public Staff data requests would have required costly remediation even in the absence of the CCR Rule and CAMA.

The reason that remediation for violations of long-standing environmental laws and regulations would have been costly even without the CCR Rule and CAMA is that the cleanup requirements so closely parallel those of the CCR Rule and CAMA. For instance, when groundwater exceedances occur, the 2L regulations require reporting to DEQ, assessment of the contamination, and that the site owner "implement an approved corrective action plan for restoration of groundwater quality at or beyond the compliance boundary…." Further, 2L requires "Removal, treatment, or control of secondary pollution sources that would be potential continuing sources of pollutants to the groundwaters, such as contaminated soils and non-aqueous phase liquids." (Lucas Exhibit 2; 15A NCAC 2L .0106) In a similar vein, the state enforcement actions brought by DEQ against DEP for the Asheville, Sutton, Weatherspoon, H.F. Lee, and Cape Fear plants all resulted in partial summary judgment orders where the court ruled that DEP's excavation actions and compliance with CAMA would remedy the alleged violations. (Public Staff Wells Cross-Examination Exhibits 8 and 9) In other words, the lawsuits to enforce cleanup of groundwater contamination from ash basins through injunctive relief under long-standing North Carolina law were rendered moot by the cleanup that would result from CAMA compliance. This position is well-supported in testimony of witness Lucas:

> Q. The NPDES permit requirements and the 2L groundwater standards, did they exist before CAMA and the CCR rule were adopted?
>
> A. Yes.
>
> Q. And if there is a violation, say, of groundwater standards, does 2L require the Company to take corrective action?
>
> A. Yes, it does.
>
> Q. Does CAMA require the Company to take corrective action?
>
> A. Yes, it does.

Q. If CAMA had never been passed, would the Company have had to remedy, through corrective action, the 2L violations that existed?

A. Yeah. That's a requirement in the rules.

Q. When CAMA came into play, did it require closure of five out of seven of the basins?

A. Yes.

Q. Excuse me, basins at five out of seven of the plants?

A. Yes.

Q. Okay. And is that, in effect, remedying the 2L violations?

A. Yeah. Closure of the basins would have certainly helped remedy the 2L violations.

Q. If there had been no CCR rule and CAMA, would the Company still have had to remedy the violations?

A. Yes.

Q. Is it possible that DEQ or legal judgments would have required different remedies than closure of the ash basins?

A. It could have, yeah, definitely.

Q. Is that something that it's just impossible to know because it's a scenario that did not happen?

A. Yeah. It didn't happen. Can't speculate, exactly, what the conclusion would have been without CAMA.

Q. In your opinion, would it be just and reasonable rate setting to charge consumers 100 percent of the cost of remedying environmental violations at Duke Energy basins?

A. No.

(T 19, pp 47-49) In conclusion, to a significant degree, the CCR Rule and CAMA did not create new compliance costs where environmental violations existed. Rather, they reflect a more comprehensive and detailed approach to coal ash management, but the resulting costs would largely have been incurred in any event by DEP due to its extensive past violations of 2L regulations, G.S. 143-215.1, and NPDES permit conditions.

Given the practical impossibility of identifying precisely what the costs of remediation would have been in the absence of the CCR Rule and CAMA, an equitable sharing of actually incurred coal ash costs is appropriate. Given the high number of environmental violations resulting from DEP's failure to comply with long-standing regulations and laws, it is just and reasonable to require shareholders to bear a greater portion of the costs than in nuclear plant cancellation costs, where Company culpability was not so evident.

The Company's rebuttal of the Public Staff proposal for equitable sharing is not persuasive. Witness Lucas was cross-examined about imprudence – what the Company should have done in earlier years given the knowledge it had then. As he replied, those questions miss the point of his recommendation:

> Q. Mr. Lucas, let me ask you this question, hopefully a direct one, if I ask a good one.
>
> From 1920 until 2014, with respect to my Company's ash basins in this state, what should we have done differently and when should we have done it?
>
> A. Should not have contaminated groundwater, should not have allowed unpermitted seeps, and I'm going back to the basis of my testimony. I can't say exactly what year or exactly what technologies. I know I keep repeating this. And that difficulty is why I'm recommending an equitable sharing. The Company had a responsibility to protect groundwater, had a responsibility to not allow unpermitted seeps, and a responsibility to comply with its NPDES permit limits. In many cases it didn't.

(T 19, p 35) Imprudent acts or omissions would give rise to a 100% disallowance of costs. The 50%-50% equitable sharing of coal ash costs is instead based on DEP's failure to comply with environmental laws and regulations, which shows Company culpability without regard to imprudence. The Company's challenge to the Public Staff was framed to address a different position than the Public Staff has taken.

Where DEP witnesses did challenge the Public Staff's actual position, they did not provide persuasive evidence. For witness Lucas, the central reason for equitable sharing was the extensive environmental violations, which required costly remediation. Witnesses Wright and Wells (and Kerin and Fountain) argued that the Company had an "exemplary" environmental compliance record with respect to coal ash. Witness Wright had supported the Company's coal ash costs as appropriate for rate recovery, yet when asked about particular coal ash-related environmental violations, he repeatedly indicated he lacked knowledge and he deferred the answers to witness Wells. (T 20, pp 196, 204, 208-09) Witness Wells testified that the number of NPDES violations in Lucas Exhibit 5 was incorrect, that the number of groundwater exceedances in Lucas Exhibit 6 failed to distinguish which were due to background levels, and that it was unfair to call the exceedances "violations" because DEQ was more interested in corrective action than punishment. The fact that DEQ was more interested in corrective action than punishment has nothing to do with the fact that violations exist. It is simply a reflection of how DEQ chooses to address the violations. Most importantly, the issues raised by witness Wells in his rebuttal testimony were addressed in Lucas' revised exhibits. Revised Lucas Exhibit 5 had corrected the count of NPDES violations to exclude groundwater violations. Revised Lucas Exhibit 6 expressly distinguished groundwater violations from exceedances that could be due to background levels of the regulated constituents, and still found 2,857 violations. The result was fewer coal ash environmental violations than were originally counted, but the remaining high number of environmental violations clearly supported the Public Staff's view of violations as being extensive.

In other rebuttal testimony, the DEP witnesses inaccurately restated Public Staff testimony, creating a straw man that they then criticized. Witnesses Wells and Wright distorted witness Lucas' statement that the Dan River spill was a "contributing factor" to the enactment of CAMA and the CCR Rule by claiming that witness Lucas incorrectly said that Dan River "caused" CAMA and the CCR Rule. There is ample support for witness Lucas' "contributing factor" testimony. CAMA was enacted in response to the Dan River spill, though it addressed a broader range of environmental issues associated with coal ash. Public Staff Wright Rebuttal Cross-Examination Exhibits 4 and 5 show the Dan River spill was a major impetus to the CAMA legislation. Witness Wright's opinion that legislation equivalent to CAMA would have been passed in North Carolina in the absence of the Dan River spill is unfounded speculation. Likewise, Public Staff Wright Rebuttal Cross-Examination Exhibit 3 (Federal Register publication of the final CCR Rule) shows that the Dan River spill was mentioned multiple times by the EPA in support of adoption of the Rule. Witness Wright is correct that the proposed CCR Rule was published before the Dan River spill, but this does not mean the Dan River spill did not lend further support (was a "contributing factor") to adoption of the final CCR Rule.

Witness Wright also mischaracterized witness Lucas' testimony by contending that Mr. Lucas had stated that environmental lawsuits and settlement payouts were "per se" evidence of imprudence or liability. (See T 20, pp 154, 156, 159) Witness Lucas did testify that the "sheer number of legal actions against DEP for coal ash environmental violations is also suggestive of the extent of the problem." (Emphasis added. T 18, p 283) He also stated that DEP should not have made multi-million dollar settlement payouts in its Sutton plant litigation if it did not commit violations. However, neither of these statements is presented as "per se" arguments. The central focus of witness Lucas' position is that the Company's own reporting data and responses to data requests show extensive environmental violations. That evidence is in Lucas Exhibits 5, 6, and 7 as well as his testimony.

In direct testimony, witness Lucas did testify that litigation costs should be disallowed when there is either (a) a final judgment finding violations, (b) a payment in settlement, or (c) a DEQ determination that there were groundwater exceedances at locations involved in the litigation, thereby in effect substantiating the allegations. (T 18, p 277) At hearing, witness Lucas stated that a settlement by itself would not establish violations. (T 19, pp 46-47) In any event, as the Commission has determined that the groundwater monitoring data and other evidence, independent of the settlement payments involved in this case, establish that there were groundwater violations at the Sutton plant and across the DEP system.

Witness Wells mischaracterized witness Lucas' testimony by contending that Mr. Lucas testified groundwater exceedances were "per se" evidence of violations. (T 21, pp 74-75) The original Lucas Exhibit 6 noted that it represented groundwater exceedances at or beyond the compliance boundaries for DEP plants, and further that "Highlighted fields are subject to change due to the provisional background threshold value being greater than the 2L standard or IMAC, which DEQ may determine is naturally occurring and decrease the quantity of exceedances." The original Lucas testimony carefully stated that the Public Staff had not yet determined how many of the exceedances were caused by DEP ash basins and how many were due to natural background levels of the constituents. (T 18, p 256) However, the Public Staff did further analysis (data from DEQ was received late in the Public Staff's investigation), and Lucas Revised Exhibit 6 definitively stated the 2,857 groundwater exceedances were indeed violations of 2L, not the result of background levels. Witness Lucas explained this in his supplemental testimony:

> The Revised Lucas Exhibit No. 6 contains a list that numbers the groundwater standard <u>violation</u>s. It also numbers the groundwater standard <u>exceedance</u>s that, in the future, may or may not prove to be violations, depending on whether DEQ determines they are due to coal ash or due to natural background levels. The groundwater standards are listed In 15A NCAC 2L or listed In the interim maximum allowable concentrations (IMACs).

(T 18, p 290) The Commission finds the number of 2L violations shown in Revised Lucas Exhibit 6 is correct.

In rebuttal, witness Wright further challenged the Public Staff recommendation as being inconsistent with the Public Staff's position in the 2016 DNCP rate case. He pointed out that Dominion had been sued by the Sierra Club for coal ash-related environmental violations, so that Dominion was "similarly situated" to DEP, and that the Public Staff recommended full recovery of coal ash costs in the DNCP rate case rather than an equitable sharing. (T 20, pp 135-37, 141-142) He also argued that DEP's coal ash disposal costs are "used and useful" and therefore a return is appropriate on the deferred amount. (T 20, p 142) With regard to the Sierra Club lawsuit against Dominion, witness Wright admitted the decision came after the 2016 DNCP rate case. (T 21, p 190) He admitted that in the DNCP case, there was no challenge to the reasonableness of coal ash cost recovery, whereas in the present case there were challenges. (T 14, p 140) In a series of questions, it became clear that he had not done a full comparison of the extent of coal ash environmental violations for DNCP when he claimed it was similarly situated to DEP:

> Q. In the Dominion rate case, was there any evidence that the Company had engineered unauthorized seeps from its ash basins?
>
> A. I do not know.
>
> Q. Did you review the number of unauthorized seeps for Dominion compared to the number for Duke Energy Progress?
>
> A. No, I did not . . . .
>
> Q. So, again, in comparing Dominion to Duke Energy Progress, was there any evidence in the Dominion rate case before this Commission that that company had hundreds or thousands of groundwater exceedances?
>
> A. I didn't read the evidence that was presented or that was not presented.

(T 14, pp 219-20) The Commission finds that there was no significant evidence of environmental violations in the 2016 DNCP rate case, in contrast to the present case. Nor, as a settled case with tradeoffs on various issues, can the 2016 DNCP rate case be considered as any type of precedent for regulatory treatment of coal ash.

Moreover, the Commission concludes that witness Wright is incorrect in stating that DEP's coal ash costs are "used and useful" utility property within the meaning of G.S. 62-133(b). The original cost of ash impoundments may well be in rate base, earning a return, as used and useful property. That is irrelevant to the ARO costs for compliance with CAMA and the CCR Rule (or remediation of environmental violations) that are requested in the deferral in this case. DEP has not sought to include these costs in rate base. It has requested to defer them and put them in a regulatory asset. As a matter of utility accounting, the deferral into a regulatory asset makes these costs a form of expense, which by statutory definition is different from used and useful property. Expenses, unlike used and useful utility property, are not legally entitled to a return. Indeed, this is the basis for the N.C. Supreme Court affirming an equitable sharing of cancelled nuclear plant costs in State ex rel. Utilities Com. v. Thornburg, 325 N.C. 463 (1989).

Witness Wells testified that witness Lucas had grossly overstated the number of NPDES permit violations by including a large number of groundwater exceedances. The Commission agrees with respect to the original Lucas Exhibit 5. However, witness Lucas explained that he had been misled by the label "violations" on the DEQ database for permit violations, and upon investigating further he corrected that mistake on Revised Lucas Exhibit 5. (T 19, pp 42-43) Revised Lucas Exhibit 5 showed 458 NPDES permit violations, including 203 for water quality violations (almost all at the Mayo plant) and 255 for "failure to monitor" violations. Witness Wells argued that the "failure to monitor" violations were not actually violations because they resulted from a flood or plant shutdown rather than any missed sampling by DEP. (T 21, p 90; T 22, p

45) He maintained that there were fewer than 200 NPDES violations, also noting that most occurred at Mayo. Ultimately, the testimonies of witnesses Lucas and Wells reach the same result – approximately 200 NPDES violations over 10 years at DEP plants – apart from the failure to monitor data. The Commission finds that approximately 200 NPDES violations is not by itself a basis for equitable sharing of the coal ash costs, but that it does support the Public Staff's position of extensive coal ash-related environmental violations when viewed in conjunction with the other types of violations.

For the area with the greatest number of violations identified by witness Lucas – groundwater exceedances – there is less common ground with the Company. Witness Wells argued that groundwater exceedances are a function of how modern laws have changed the way unlined basins are viewed. However, the 2L regulations were adopted in 1979, and witness Wells' own testimony shows the corrective action requirements were added to 2L around 1983. Thus, over 30 years have elapsed since DEP was required by the State's 2L regulations to prevent and correct groundwater contamination. Given that many violations have been determined in recent years when more monitoring wells have been installed, and that 2L has been the law for over three decades, the Commission is not persuaded that the fact that there were changing environmental regulations should excuse the 2,857 violations shown in Revised Lucas Exhibit 6.

Likewise of concern to the Commission, witness Wells testified that DEP has taken every action required by DEQ and CAMA to address groundwater impacts. In fact, DEP litigated for years against the DEQ efforts to obtain corrective action through its state court enforcement cases. (See Public Staff Wells Cross-Examination Exhibits

6, 7, 8, and 9: the DEQ lawsuits were brought in May and August of 2013, but not resolved for five plants until April and June of 2016.) Moreover, the 2L regulations require first and foremost that groundwater exceedances be prevented, whereas witness Wells touts the virtue of the Company's efforts to clean up its violations. The Commission finds that the large extent of groundwater violations is not a model of compliance as the Company witnesses claim; rather, it shows a widespread failure to comply.

Witness Wells testified that unlined ash basins were the primary technology when DEP built its basins between 1956 and 1985. (T 21, p 67) The Commission agrees. At the same time, this fact is more relevant to a prudence analysis than to the equitable sharing issue. The Commission accepts that the DEP approach to ash basin construction (i.e., no liners) was consistent with a majority of other electric utilities in the 1956 to 1985 period. Whether DEP should have known in past decades that ash basins could contaminate groundwater in the absence of liners is less clear. Public Staff Wells Cross-Examination Exhibits 3 and 4 show that DEQ had copied DEP on a 1978 letter about the need to monitor for groundwater contamination in connection with the proposed Mayo ash basin, and that the risk of groundwater contamination from coal ash basins was identified in a 1979 scientific conference paper. It is apparent that there was some understanding of groundwater risk well before industry standards changed. However, the salient fact is that once 2L regulations were adopted in North Carolina, the Company had a legal duty to prevent groundwater contamination, and a secondary duty to take corrective action where contamination did occur. Following standard industry practice did not exempt DEP from its legal duty to comply with 2L groundwater standards.

In this regard, the Commission finds it was unreasonable for DEP to delay installation of comprehensive groundwater monitoring wells for years after the 2L groundwater quality requirements became effective. DEP installed seven wells at Sutton in 1984, five more in 1990, five at Weatherspoon in 1990, three at Roxboro in 1987, and the remainder of monitoring wells beginning in 2006. (Public Staff Wells Cross-Examination Exhibit 5, response to data request 27-13) This was a paltry number of monitoring wells; indeed, prior to the commencement of DEQ enforcement actions in 2013 the Company had only installed 161 wells across all its North Carolina plants. By contrast, in November of 2017 with comprehensive assessment required in the wake of CAMA, the Company had installed 696 groundwater monitoring wells. (Public Staff Wells Cross-Examination Exhibit 5, response to data request 27-14) The disparity shows that DEP was not making an effective effort to assess its groundwater compliance until after the Dan River spill brought attention to ash basin environmental problems. Witness Wells observed that 2L did not create a legal duty to install monitoring wells; only later – starting in 2008 – did DEQ start to systematically add groundwater monitoring to NPDES permit conditions. (T 21, p 69) However, given the duty to comply with 2L developed in 1979 through the early 1980s, it was not possible for DEP to know if it had significant violations requiring corrective action without monitoring. It appears that the Company simply relied on lack of enforcement action by DEQ, which is not a reasonable strategy either in terms of actually complying with the regulation or in terms of proactively avoiding greater cleanup costs in the future by identifying problems in earlier years before they spread far or accumulated.

Witness Wells disagreed with witness Lucas' statement that comprehensive monitoring and remediation did not begin until after the state enforcement litigation (2013), the Dan River spill (2014), and CAMA (2014). However, as noted above, the number of monitoring wells prior to 2013 was 161 – hardly comprehensive compared to the 696 in November of 2017. The importance of having a large number of monitoring wells was noted in the Federal Register publication of the CCR Rule. Page 21455 states "once monitoring is put in place, new damage cases quickly emerge." Further, the CCR Rule cited North Carolina as an example, noting that as new monitoring wells were required in 2012, DEQ "disclosed that elevated levels of metals have been found in groundwater near surface impoundments at all of the state's 14 coal-fired power plants." (T 21, p 174; Public Staff Wright Rebuttal Cross-Examination Exhibit 3) As far as comprehensive remediation is concerned, witness Wells admitted that prior to 2013, DEP had not implemented corrective actions. (T 21, p 170) In short, witness Lucas was correct in stating that comprehensive monitoring and remediation did not begin until after the state enforcement litigation, the Dan River spill, and the enactment of CAMA.

Witness Wells mischaracterized witness Lucas' testimony as saying that North Carolina's groundwater laws were intended to be punitive. (T 21, pp 73-74) Witness Lucas had testified that the 2L regulations were "effectively a strict liability – old impoundments are not grandfathered, and no showing of imprudence is required to establish a violation of 2L rules. That is, DEP had a duty to comply without regard to whether they followed accepted industry practices." (T 18 p 272) Nowhere does witness Lucas state or imply that 2L is meant to be punitive.

Witness Wells testified that 2L is not punitive because DEQ has a practice of working with the permit holder to achieve corrective action rather than seeking to fine the permit holder. From this, he concluded that the groundwater laws are not intended to be used to deny cost recovery in utility rate cases. This analysis is misplaced for two reasons. First, 2L can be punitive; the choice is up to DEQ. G.S. 143-215.6A allows DEQ to assess civil penalties and G.S. 143-215.6B allows criminal penalties for violations of the 2L groundwater standards. Second, and more importantly, whether 2L regulations are intended to be punitive, or not, is largely irrelevant to the question of equitable sharing in rate cases. The important consideration is whether DEP committed extensive coal ash-related environmental violations that required costly remediation, not whether DEQ pursued corrective action instead of fines.

Witness Wells stated that witness Lucas "conflates" groundwater exceedances with groundwater violations. (T 21, pp 74-76) As noted above, witness Lucas did not conflate the two; his Revised Exhibit 6 and testimony clearly distinguish exceedances that are violations of 2L from those that may turn out to be caused by natural background levels of regulated constituents. Nor does the fact that DEQ chooses to pursue corrective action for exceedances, instead of fines, mean that there is no violation. 15A NCAC 2L.0106(e) provides that anyone responsible for an exceedance at or beyond the compliance boundary is required to provide DEQ with an assessment of the "violation" and required to submit a corrective action plan. Thus, the term "violation" is not dependent on DEQ seeking enforcement through a fine. By suggesting otherwise, DEP has improperly sought to diminish the appearance of the extent of its violations.

Essentially the same flaw appears in witness Wells' testimony that extraction wells would have been the normal course of CAMA and CCR Rule corrective action even without the Sutton settlement between DEP and DEQ. (T 21, pp 76-77) This argument ignores the point that corrective action under CAMA, just as under 2L and the Sutton settlement, depends on there being a groundwater violation to correct. Extraction wells may be "normal" corrective action under CAMA, but there is nothing normal about having groundwater violations that prompt the corrective action. The essence of witness Lucas' recommendation to exclude the costs of extraction wells is that the cost is over and above what the CCR Rule and CAMA would have required in the absence of DEP's groundwater violations.

Witness Wells also stated that witness Lucas had suggested the amount of litigation against DEP suggested DEP was imprudent, and that such a suggestion was wrong. (T 21, pp 77-79) In fact, witness Lucas did not suggest the amount of litigation indicated "imprudence." In connection with the Public Staff's equitable sharing proposal, rather than in an imprudence adjustment, he testified that the amount of litigation on coal ash was <u>also</u> suggestive of the extent of the environmental violations problem. (T 18, p 71) This was offered as cumulative evidence in addition to the groundwater exceedances and unauthorized seeps which were reported by DEP. At hearing, witness Lucas explained that a lawsuit by itself, or a settlement by itself, would not establish a violation. Instead, he determined that the Company's own groundwater monitoring data established that there were in fact groundwater violations to support the allegations in the legal claims against DEP. (T 19, pp 46-47)

Witness Wells sought to minimize the evidentiary importance of the litigation by testifying that it was driven by non-governmental organizations (NGOs), implying that the type of plaintiff made the allegations less credible. (T 21, pp 77-79) The Commission does not agree with this analysis for two reasons. First, DEQ – not just environmental organizations – brought state court enforcement actions against every DEP coal-fired plant in North Carolina for coal ash-related environmental violations. DEQ may have been prompted by the NGOs' notices of intent to sue, but DEQ vigorously litigated those lawsuits against DEP until CAMA rendered them moot. The U.S. Department of Justice also brought the criminal case for violations at the Cape Fear and Asheville plants. Second, where lawsuits have been resolved without a finding that environmental violations either existed or did not exist, as happened for most of the state enforcement actions against DEP, the quality of the evidence supporting the allegations is what matters, not the identity of the plaintiff. As discussed earlier in connection with the Sutton plant, there was overwhelming evidence supporting allegations of groundwater violations. Revised Lucas Exhibit 6 and Lucas Exhibit 7 demonstrate extensive groundwater violations at all eight DEP plants serving the Carolinas. Likewise, witness Lucas' testimony at hearing showed that he relied on the groundwater exceedance data from DEP as supporting the allegations rather than just assuming the allegations were valid. (T 19, pp 46-47) The Commission agrees with DEP that the amount of litigation by itself is not evidence of violations; however, in this case, the amount of litigation corroborates the sampling data that shows actual violations.

Witness Wells mischaracterized witness Lucas' testimony as saying that any exceedance, no matter how minor or long ago, should lead to denial of cost recovery. (T 21, p 79) This was likely a reference to deposition testimony, introduced at hearing, where witness Lucas stated that any violation of environmental laws was mismanagement. (T 19, p 31) Again, the Company is setting up a false straw man. Witness Lucas testified repeatedly that he was not conducting an imprudence analysis in connection with his equitable sharing proposal. Imprudence requires an act or omission that was unreasonable based on what was known at the time the act or omission occurred, not based on hindsight. The Company kept asking witness Lucas what particular actions it should have taken or what omissions it should have avoided decades earlier. Witness Lucas rejected this attempt to reframe his recommendation in terms of prudence analysis. (T 19, p 35) He stated he was not taking the position that a particular technology should have been used by DEP at a particular time to be prudent. (T 19, p 36) Instead, he focused on the duty to comply with environmental regulations: "the Company can't sit there and claim, in order for us to generate electricity, there are no reasonable steps we could have done to prevent contamination of groundwater…." (Id.) Witness Lucas testified that, "An equitable sharing is particularly appropriate in light of the extent of the Company's failure to prevent environmental contamination from its coal ash impoundments, in violation of state and federal laws." (T 18, p 282) He then listed a wide range of circumstances in support of his position that the great extent of violations justified an equitable sharing. (T 18, pp

282-85) This was echoed by Public Staff witness Maness as one of his two general reasons for proposing equitable sharing: “the extent of the Company’s failure to prevent environmental contamination from its coal ash impoundments, in violation of state and federal laws, supports ratemaking that leaves a large share of the costs for DEP shareholders to pay.” (T 18, p 309)

Witness Wells continued his rebuttal by asserting that exceedances are normal, and not violations, where they occur at facilities built without liners, and that regulatory compliance is a matter of taking corrective action. He stated:

> The 2L rules' corrective action provisions are deliberately designed around the idea that older facilities, built before liners were a regulatory obligation, were likely to have associated groundwater impacts, that such impacts were not the result of regulatory noncompliance, and that such impacts should be addressed in a measured process. Compliance with this process is not mismanagement and should not be held against the Company in the area of cost recovery.

(T 21, p 80) It is true that the corrective action provisions of 2L are designed to address groundwater “impacts” (exceedances due to coal ash and not due to natural background levels). However, it is inaccurate to state “such impacts were not the result of regulatory noncompliance.” The fact that there is an exceedance of 2L groundwater standards for regulated constituents, at or beyond the plant compliance boundary, and not due to natural background causes, means as a matter of law there is a violation. As discussed earlier, the 2L regulations expressly state that is so. The 2L regulations require prevention of groundwater contamination; the fact that they also provide for corrective action if prevention is not achieved, does not mean the failure to prevent is not a violation.

Finally, witness Wells said witness Lucas has implied that seeps at ash basins would have required basin closures. (T 21, pp 22-26) Once again, this is not what witness Lucas said. In response to a Commissioner question, he stated: "We can't specifically conclude, if there had never been a CAMA, what would the Division of Water Quality, or as it says earlier, or now, the DEQ, what they would have done of [sic: about] the seeps, but these seeps are illegal under state rules." (T 19, p 74) Witness Lucas observed that the DEQ state court enforcement actions involving the Asheville, Sutton, Cape Fear, H.F. Lee, and Weatherspoon plants all resulted in partial summary judgments on the grounds that closure under CAMA would remedy all the violations (including seeps and groundwater) alleged in the lawsuits. (T 18, pp 257-59) With respect to other types of violations, he stated:

> Moreover, DEP's non-compliance with NPDES permits and 2L rules would in all probability have led to cleanup costs from environmental litigation or enforcement even if the CCR Rule and CAMA had never been adopted. Those cleanup costs would have largely overlapped CCR Rule/CAMA compliance costs because impoundment closure would be a primary cleanup method.

(T 18, p 284) This is not to say the environmental violations would have necessarily required closure, but rather that closure under CAMA would provide a remedy for the environmental seeps. Of course, witness Lucas also recognized that DEP's effort to obtain near term regulatory compliance for its unlawful seeps, prior to basin closures, involved seeking to include the seeps in its NPDES permit renewals, and where that was not possible, complying with a special order by consent to correct the seeps. (T 19, p 74) In brief, his testimony was quite different from saying the seeps would require basin closures.

In summary on the Public Staff's equitable sharing proposal, the Commission finds and concludes that

A. There are extensive environmental violations resulting from DEP's failure to comply with groundwater and surface water regulations at all eight DEP coal-fired plants, across a period of many years. These violations include numerous unauthorized seeps that DEP has admitted, and 2,857 groundwater violations confirmed by DEP's own groundwater monitoring data.

B. The coal ash-related environmental violations have a cost. Because corrective actions under CAMA and the CCR Rule, including the closure of all DEP ash basins, will remedy the environmental violations, it is not feasible to identify all the costs that would have been incurred to remedy violations under the pre-existing environmental regulations and laws, such as 15A NCAC 2L, if CAMA and the CCR Rule were not in effect. The corrective action requirements of CAMA and the CCR Rule bear substantial similarity to those of pre-existing environmental laws and regulations such as 2L. There is no doubt that substantial remedial costs would have been incurred without CAMA and the CCR Rule, but they cannot be quantified without undue speculation.

C. DEP has culpability for its environmental violations, even without a showing of traditional imprudence. The Company had a duty to comply with long-standing North Carolina environmental regulations; it failed that duty, and there are resultant costs. It would be manifestly unjust to require ratepayers to bear all the deferred coal ash costs where those costs include corrective actions to remedy the Company's environmental violations.

D. Given the extensive environmental violations caused by DEP, and the impossibility of knowing the precise cost of remedying the environmental violation costs in the absence of CAMA and the CCR Rule, it is just and reasonable pursuant to G.S. 62-133(d) to achieve in rates an equitable sharing of deferred coal ash costs submitted for recovery in this proceeding. The equitable sharing applies only to deferred coal ash costs not otherwise disallowed in this Order.

E. A 50%-50% equitable sharing between ratepayers and shareholders, to be achieved by a 26-year amortization of deferred coal ash costs, with no return on the unamortized balance, is just and reasonable in the circumstances of this proceeding.

Public Staff Proposal for Provisional Cost Recovery

Public Staff witness Maness stated that coal ash 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 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. (T 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. (T 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. (T 18, p 254) In supplemental testimony, witness Lucas was able to update the groundwater violations of the 2L regulation (T 18, p 290; Revised Lucas Exhibit 6), but unanswered questions remained about which unauthorized seeps would require remedial action under future DEQ determinations and CCR Rule groundwater violations. The Commission finds that until EPA or its designee reviews the monitoring data on CCR Rule groundwater constituents, and until DEQ makes a decision on whether any currently unauthorized seeps will require corrective action, the full extent of violations is provisional. Therefore it is proper to treat the associated cost recovery as provisional.

Similarly, there are pending lawsuits against DEP regarding the Mayo and Roxboro plants that allege violations of environmental laws. (T 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. Accordingly, the associated cost recovery is properly treated as provisional.

Provisional cost recovery is appropriate in certain circumstances. Where rates are put into effect, with notice that there may be a future refund to reflect a specified circumstance, the decision is not unlawful retroactive ratemaking. See State ex rel. Utilities Com. v. Nantahala Power & Light Co., 326 N.C. 190, 205. Indeed, in the present case, DEP stated that it would provide a future offset to customers for any insurance proceeds it wins in its claims against insurers on coal ash. The Commission has provided for provisional treatment of the federal corporate income tax changes in its January 3, 2018, order in Docket No. M-100, Sub 148. The pending determinations by DEQ, EPA, and certain courts that will establish whether past actions of DEP amount to environmental violations are likewise circumstances justifying provisional cost recovery.

The “Run Rate” Proposal for Future Coal Ash Costs

DEP proposed for future coal ash costs a “run rate” of approximately $129.1 million per year to be included in rates in the present case, and to be trued up in future rate cases against the costs actually incurred in the future. (T 6, pp 123-24) In contrast, the Public Staff proposed that coal ash costs incurred after August 31, 2017, be deferred to a regulatory asset and allowed to accrue a return until the next rate case, with the regulatory treatment of those costs to be determined in future rate cases. (T 18, pp 299, 316-17) Witness Maness explained that recovery of future coal ash costs as ongoing operations and maintenance (O&M) expense in rates, or a “run rate,” could make any future equitable sharing of costs much harder to achieve. (Id.) In rebuttal, witness Bateman testified that the Company was opposed to any sharing of coal ash costs, that it was appropriate to include an ongoing amount in rates because those costs would be recurring in the future, and that denial of a "run rate" would create cash flow short falls for DEP, negatively affecting its credit metrics. (T 7, pp 144-45)

The Public Staff's proposal would allow the Company to defer its future or ongoing coal ash costs into a regulatory asset, with a return until the ratemaking treatment is determined in the next rate case. The Commission finds this is a reasonable approach to preserve for DEP the possibility of recovering all its future coal ash costs, subject to future determination of whether any costs should be disallowed as unreasonable or any sharing should be ordered to achieve just and reasonable rates. Deferrals of extraordinary expenses are a well-established ratemaking practice in North Carolina. DEP sought, and in this Order has been granted, deferral treatment of its coal ash costs incurred from January 2015 through August 2017. The same approach is reasonable for future coal ash costs. It is especially reasonable given the uncertainty of the amount of future coal ash costs. The Commission finds that it is important to keep open for future rate cases the ability to decide whether equitable sharing will be appropriate for future coal ash costs. It certainly is not in a position to judge the reasonableness of future rates, with respect to coal ash, at the present time. The North Carolina Supreme Court has affirmed the Commission's ability to defer expenses and decide on equitable sharing in a future rate case (see State ex rel. Utilities Com. v. Thornburg, 325 N.C. 463 (1989)); other ratemaking approaches to create an equitable sharing are legally untested and thus create legal uncertainty.

The Company is correct that it will have less cash flow as a result, but this is a risk that investors should have incorporated into their expectations that inform the cost of capital. The implication of the Company's cash flow argument is that there should be no regulatory lag, and while DEP has enjoyed substantial progress in recent years toward that goal in the form of various riders, some degree of regulatory lag is a necessary function of the statutory ratemaking framework. DEP has prospered, and provided reliable electric service, within that framework. In conclusion, the Commission agrees with the Public Staff's recommendation to deny the request for $129.1 million in annual revenues for future coal ash costs (the "run rate") in rates. It is reasonable and appropriate to allow DEP to defer its future coal ash costs into a regulatory asset, with a return until the next rate case, and decide the appropriate ratemaking treatment of those costs in the next rate case.

Impact on DEP's Credit Metrics

DEP witnesses Bateman, Hevert, and De May each testified that Commission approval of the Public Staff's recommended sharing of certain coal ash costs would affect DEP's cash flows, which could negatively affect DEP's credit metrics. However, none of these DEP witnesses stated the extent to which DEP's credit ratings would be affected or quantified the effect, if any, on DEP's cost of capital, including debt costs.

During cross examination by the Public Staff, DEP witness De May testified that the latest DEP Moody's Investors rating was January 31, 2017, and that DEP was rated Aa3 for its secured debt including its First Mortgage Bonds. Public Staff De May Cross Examination Exhibit 1 was entitled "Interest Rates," the source of which was the Council of Economic Advisors, Economic Indicators, various issues, Mergent Bond Record.

This exhibit listed the interest rates for Moody's rated Aa Utility Bonds and Moody's rated A Utility Bonds for each year 1975 through September 2017. Mr. De

May testified that Moody's rating A is the next credit rating lower than DEP's Aa3 for its secured First Mortgage Bonds. He admitted upon cross examination that the differential in the Aa Utility Bonds and A Utility Bonds for the five-year period 2012 through 2016 was an average of .19% (19 basis points) and the average monthly differential in 2017 through September was .18%.

Public Staff De May Cross Examination Exhibit 2 was a DEP data request response to Public Staff Data Request 119-10, which listed DEP's debt as of August 31, 2017, plus September debt issuances. This exhibit listed on line 21, First Mortgage Bond Taxable totaling $300 million issued September 8, 2017, with a floating 1.50% interest rate and three-year term. This exhibit also listed on line 22, First Mortgage Bond Taxable totaling $500 million issued September 8, 2017, with a fixed 3.60% interest rate and 30-year term. Witness De May testified the 3.60% was DEP's lowest interest rate ever on 30-year First Mortgage Bonds.

Public Staff De May Cross-Examination Exhibit 3 listed the DEP bonds with maturity dates for the seven-year period 2018 through 2024. This exhibit was based upon the listings on DEP's data request response, Public Staff Cross Examination Exhibit 2, and reflected no bond maturities in 2018, 2023, and 2024, and a total of $2.450 billion in maturities in the four-year period 2019 through 2022. The earliest maturity date for a listed bond was January 15, 2019, with a principal of $600 million, a 5.30% interest rate, and a 10-year term. Mr. De May admitted upon cross examination that when DEP refinanced the $500 million September 8, 2017, First Mortgage Bond at 3.60%, the interest rate was 170 basis points lower than the 5.3%.

Mr. De May testified upon cross examination that the requested DEP coal ash costs were about $300 million, amortized over five-years, resulting in approximately $60 million per year, including a return on the unamortized balance. Public Staff De May Cross Examination Exhibit No. 4 was a calculation of the refinancing of the next maturing DEP bond on January 15, 2019, of $600 million using the .19% (19 basis points) recent five-year differential between the Moody's rated Aa Utility Bonds and Moody's A rated Utility Bonds, where the annual interest increase would be $1.14 million. Witness De May accepted the mathematical calculation, but disputed the analysis. Witness De May admitted on cross examination that the Public Staff's recommendation would result in a sharing of certain coal ash costs between customers and DEP shareholders, based on a 26-year amortization with no return on the unamortized balance, resulting in approximately $6 million per year customer paid revenue. He further admitted the $1.14 million added to the $6 million totaled $7.14 million per year, which was less than DEP's requested $60 million per year.

Public Staff De May Cross Exhibit No. 5 (Item 23 a-b of DEP's E-1 filing) was introduced into evidence, which is a DEP Financial Forecast for the five years 2017 through 2021. On cross examination, Mr. De May testified that DEP's net financing each year would be 2018 - $380 million, 2019 - $459 million, 2020 - $(206) million and 2021 - $151 million. The four-year average would be only $196 million per year.

On December 6, 2017, DEP filed a late filed exhibit at the request of Commissioner Clodfelter showing the DEP debt service coverage, historically and currently. Witness De May testified that cash flow as a percentage of debt is the most important financial ratio for credit agencies. This late filed exhibit stated Moody's calculated current FFO/Debt (denominated in the report as CFO Pre-WC/Debt) as of September 30, 2016, was 21%, with 2014 at 26% and 2015 at 21%. This late filed exhibit did not state the FFO/Debt for any date in 2017.

The Commission concludes that DEP has failed to provide credible and persuasive evidence that adopting the Public Staff's recommendation for equitable sharing of coal ash costs would be detrimental to DEP's credit metrics. There is no evidence in the record showing that DEP would be deemed risker by the investment community as a result of equitable sharing of coal ash costs. While the DEP witnesses opined that DEP's credit metrics would be negatively affected, they provided no probative qualitative or quantitative evidence to substantiate their opinions.

In particular, there is no evidence that the lower revenues resulting from equitable sharing of coal ash costs will actually cause a credit downgrade. Such causation is purely speculative. Further, even if there were to be a credit downgrade, there is no evidence, as discussed immediately below, that a downgrade would cost DEP ratepayers more than the savings they will gain from the equitable sharing of coal ash costs.

Public Staff De May Cross Examination Exhibit 1 lists all DEP's long-term debt, with lines 6 through 16 and lines 18 through 22 being all First Mortgage Bond Taxable, which is secured debt with Moody's Aa3 rating, and totals $6.775 billion. Lines 23 through 25 are also long-term secured debt totaling $.348 billion. The only unsecured long-term DEP debt on this exhibit, excluding capital leases, is line 5 listed as Commercial Paper LTD totaling $.150 Billion, which constitutes only 2.1% ($.150 billion divided by $7.263 billion) of DEP's long-term debt. Witness De May testified the DEP Moody's secured credit rating was Aa3 and unsecured was A. Public Staff De May Cross Examination Exhibit No. 1 clearly showed the rate differential between Utility Aa Bonds and the next lower Utility A Bonds for the years 2012 through 2016 averaged.19%, including a monthly 2017 average of .18%. The Commission observes that in the past 25 years from 1992 through 2017, the average annual differential is .18%. While a .18% differential could result in marginal increased costs for customers, any such increase would be significantly outweighed by the cost savings they will experience as a result of the Public Staff's equitable sharing proposal.

The Commission observes that on September 16, 2016, when DEP had an FFO to Debt ratio of 21%, DEP (with its Aa3 secured credit rating) issued $450 million of 30-year, First Mortgage Bonds Taxable at 3.70% interest rate, which compares favorably to the 3.73% rate for 2016 Utility Bonds Aa listed on Public Staff De May Cross Examination Exhibit 1. In addition, the September 8, 2017, issue of 30-year First Mortgage Bond Taxable with Aa3 secured credit rating totaling $500 million with an interest rate of 3.60% (lowest ever by DEP), compares favorably to the 3.70% September 2017 average rate for Utility Bonds Aa on Public Staff De May Cross Examination Exhibit No. 1. The September 16, 2016, 30-year First Mortgage Bond Taxable was rated by Moody's Aa3 when the Moody's FFO/Debt ratio calculation was 21%. DEP was not collecting revenues from customers for coal ash remediation costs on either of these dates, nor had it obtained a Commission order shedding any light on expected recovery. Thus, even while significant uncertainty existed regarding the recovery of coal ash remediation costs, DEP obtained very favorable interest rates.

The Commission's approved annual revenue increase in this proceeding totaling $$142,304,000, will improve DEP's FFO. The Commission further finds the certainty provided by this Order with respect to coal ash cost recovery, alleviates financial risk caused by uncertainty that the Commission could have ordered a greater disallowance of coal ash costs as proposed by intervenors other than the Public Staff.

Witness Maness recommended two adjustments to the jurisdictional allocation factors used by the Company to allocate system-level coal ash 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 a factor that did not allocate costs to the South Carolina retail jurisdiction. Witness Maness testified that Company witness Bateman stated in her testimony that there is a small portion of coal ash management costs that is "specific to CAMA, unique to North Carolina and appropriate for direct assignment to North Carolina," and that 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 N.C. retail allocation factors for its CAMA Only costs that did not allocate any of the system level costs to South Carolina retail operations. Mr. Maness stated, however, 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. (T 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, that 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 rule. (T6, 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 coal ash 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. While the costs in question were required pursuant to North Carolina law, that does not change the fact that 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 operations and maintenance expenses, which are allocated to the entire DEP system, because the electricity produced by incurring those costs is transmitted and distributed throughout the entire system.

The Commission concludes that these coal ash 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; it is thus understandable that the Commission would restrict their allocation 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; the legislature could not require a similar freeze to be established with regard to South Carolina retail customers. In contrast, coal ash cleanup costs, even if required by the General Assembly, are by their nature directly and closely associated with the production of electricity for the entire DEP system. A small number of DEP's North Carolina customers will receive water supply protection; however, all DEP customers in North Carolina and South Carolina benefited from the electricity generated from the coal, so it is reasonable for all those customers to contribute toward the remediation associated with the coal.

The second adjustment recommended by witness Maness to the jurisdictional allocation factors used by the Company to allocate system-level coal ash costs to the North Carolina retail jurisdiction is to allocate all coal ash expenditures by the energy allocation factor, rather than the demand-related production plant allocation factor. Witness Maness testified that he recommended this change because the coal ash costs are being incurred due to the fact that the coal ash was produced by the burning of coal to produce energy over the years and, like the cost of coal, should be allocated by energy, and not peak demand. Therefore, the energy allocation factor should be used to determine the North Carolina retail portion of these costs. (T 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 coal ash ponds. 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, use of the demand-related factor is also consistent with end-of-life nuclear fuel costs in nuclear decommissioning costs. (T 10, pp 289-90)

Mr. 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, Mr. 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; 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. (T 19, pp 81-82)

The Commission has carefully considered the evidence presented by the witnesses. The evidence seems to indicate 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 historically 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 coal ash clean-up costs on both sides – production plant or energy. However, the Commission believes that in this case, it must pay particular attention to the unusual and extraordinarily large nature of the coal ash cleanup costs currently being incurred by the Company. These are not the ordinary types or amounts of coal ash-related costs that one would have expected (or that in this case the Company specifically expected) for the end of life of a coal production plant prior to the Dan River incident and if the plant was operated up to expected standards over its life. In the normal course of operations, it might be appropriate to include those costs in the mass of end-of life costs that are allocated as part of production plant, even if the costs considered in isolation would be related to energy more than to demand. However, in this case, given the magnitude of the coal ash costs and the nature of their incurrence, the Commission believes that it is more appropriate to consider them in isolation. In doing so, it is clear to the Commission that coal ash cleanup costs are directly related to coal ash itself, which is a residual of the burning of coal, a clearly energy-related event. Additionally, it is worth noting that in general, the more coal that was burnt, the more coal ash there is left to deal with, and the more cost that needs to be incurred. Therefore, the Commission concludes that the only appropriate and reasonable course of action to take in this proceeding is to allocate those costs by the energy allocation factor.

<u>EVIDENCE IN SUPPORT OF FINDINGS OF FACT AND CONCLUSIONS NOS. 50-52</u>

The evidence supporting these findings of fact can be found in the testimony of Company witnesses Kim McGee and Jon Kerin and the testimony of Public Staff witness Jay Lucas.

In her direct testimony, Company witness McGee testified that the beneficial reuse of coal ash 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). (T 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. (T 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 coal ash 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 coal ash 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. Therefore, 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. (T 10, p 105) Finally, witness McGee cited certain statements of the Commission in a 2016 Commission Report to the North Carolina General Assembly[11] ("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. (T 10, pp 105-06)

In his direct testimony, 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. (T 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 coal ash. As a means to handle that by-product, ash is sold to the Brickhaven mine to be used as structural fill, which is a beneficial reuse. (T 16, p 117)

---

[11] *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.

In his direct testimony, Public Staff witness Lucas testified that the costs relating to the disposal of coal ash at Brickhaven, to the extent they are reasonable and prudent, should be recovered in base rates and not through the fuel adjustment clause, because the costs did not result from the sale of coal ash. (T 18, p 230) Mr. 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". (T 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."[12] In its Limited Petition to Intervene in this case, Charah stated that it is a contractor of DEP and is engaged in the remediation of coal ash from one or more DEP facilities. (T 18, p 19)

Witness Lucas explained that in July of 2014, DEBS, on behalf of DEC and DEP, issued a bidding event for the excavation, transportation, and off-site storage of the full volume of ash at four sites: Riverbend, Dan River, and Sutton in North Carolina and W.S. Lee in South Carolina. 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,

[12] http://charah.com

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. (T 18, p 232) The purchase of coal ash 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. (T 18, p 233)

Witness Lucas described the contractual arrangement between DEBS and Charah regarding the removal of coal ash 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., Charah's) Pricing Schedule was set forth as Exhibit E. The Pricing Schedule included both fixed pricing and per ton pricing. The fixed pricing was for mobilization, site preparation, erosion, and sedimentation control work. The per ton pricing was for excavation, loading and transportation, unloading, development, placement, home and field office overhead, and profit. (T 18, pp 233-34) DEBS and Charah entered into Purchase Orders authorizing Charah to transport ash from Sutton by truck to Brickhaven and then to construct and transport ash by rail to Brickhaven. Purchase Order 1107196 constituted the vast majority of the excavation, transportation, and disposal work for Sutton; twenty change orders were executed for this Purchase Order. (T 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 coal ash to "net" against the cost of the services provided by Charah. (T 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 coal ash when setting the cost of services provided by Charah, the Company responded that it had no responsive documents. In addition, when asked how much Charah paid the Company for the Sutton coal ash, the Company responded that "there is not a defined price in the operative documents for the Sutton ash." (T 18, p 236)

Mr. Lucas testified that DEP and Charah knew how to assign a value to coal ash in a sale: pursuant to a Master By Product Marketing, Sales, and Storage Agreement (Agreement) entered into by DEC, DEP, and Charah in December of 2013, and associated Work Orders, Charah was obligated to purchase coal ash from DEP or DEC, as applicable, at a price as set forth in the Work Orders. This Agreement formed the basis for the sale of coal ash at the Belews Creek and Marshall plants via Work Orders entered into by DEC and Charah on January 1, 2014. (T 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 coal ash to Charah. Although one of the general provisions of the Master Contract stated that the services to be performed by Charah constituted payment by Charah for the ash, DEP has admitted that there was no defined price for the ash and no documentation showing that the parties assigned any value at all to the ash. (T 18, pp 236-37) The specific provisions of both the Master Contract and Purchase Orders overwhelmingly point to a contract for services, not a sale.

Mr. 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 coal ash are recoverable through the fuel clause. The General Assembly in the legislation directed the Commission to specifically address in its report "possible revisions to the current policy on allowed incremental cost recoupment that would promote reprocessing and other technologies that allow the re-use of coal combustion residuals stored in surface impoundments for concrete and other beneficial end uses". The Commission's Report examined the statutory framework for cost recovery and concluded that current policies and practices are adequate to encourage re-use of CCRs for concrete 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 re-use." On page 14 of the report, the Commission recognized that "sales of CCRs typically result in immediate net costs to ratepayers." The Commission did not conclude in its report that the costs of processing coal ash for beneficial use, without a sale, are recoverable in the fuel clause. (T 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. Mr. Lucas stated that if there is an actual sale of coal ash, cost recovery through the fuel clause may be appropriate, if the costs are reasonably and prudently incurred. Where, however, there is a contract for services not involving a sale of coal ash, costs arising from that contract should not be recoverable through the fuel clause. Mr. Lucas concluded that the true purpose of moving coal ash from Sutton to Brickhaven is environmental remediation and the disposal of coal ash. It is not the sale of a byproduct. (T 18, pp 238-39)

In her rebuttal, Company witness McGee disagreed with Mr. 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 coal ash. 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 ash from Duke Energy to Charah. She further asserted that the coal ash had value to Charah in that it was used in a process as a substitute for an alternative material. Without the purchase of the coal ash, Charah would have needed to procure topsoil or another material to use as structural fill, an added cost that Charah was able to avoid. She concluded that the overall economics of the sales agreement therefore reflected the intrinsic value of the coal ash. (T 10, p 111)

Ms. McGee identified two provisions of the Master Contract in support of her position. First, per Section 3 of Exhibit B to the Master Contract ("Exhibit B"), the Company transferred title to, risk of loss of, and responsibility for the coal ash to Charah once the coal ash is loaded in to truck or railcar at Sutton for transportation to Brickhaven. According to witness McGee, this provision indicates that the coal ash had value to the parties that had to be transferred through title. Further, the fact that Charah agreed to accept the transfer of title and risk of loss at the point that the coal ash was loaded onto its trucks or rail cars for delivery is strong evidence that the coal ash had transferable value. (T 10, p 112)

Ms. 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...." Ms. McGee asserted that this section clearly acknowledges that the coal ash serves as partial consideration for the services rendered by Charah. She stated that it was therefore understood and accepted by both parties that the service fee charged by Charah for its services was offset by the value of the coal ash to Charah, thereby constituting a sale. (T 10, p 112)

Witness McGee also took issue with Mr. Lucas' characterization of the arrangement as a "disposal". She stated that the coal ash at Sutton was not thrown away or placed in a landfill, but replaced the topsoil that would have been used as structural fill in the reclamation of the Brickhaven mine. Further, the EPA definition of beneficial re-use 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, the use of the Sutton ash as structural fill for the Brickhaven mine indicates that the ash was a valuable commodity. (T 10, p 113)

Ms. 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 coal ash, which is expressed in the contract. Accordingly, the purpose of this transaction was the sale of coal ash produced at the Company's Sutton coal plant to Charah for beneficial reuse at Brickhaven. (T 10, pp 113-14)

Finally, Ms. McGee testified that the Company has included the gain/loss of coal ash in the fuel adjustment clause in the past. Specifically, she noted that the losses on the sale of coal ash from the Asheville plant to the Asheville Airport as structural fill have been included in the fuel adjustment clause since 2008. (T 10, p 114). She noted that the Master Contract had the same language as that used for the ash from the Asheville Plant, and that the sale of the ash was implied since both parties agreed that both the value of the ash and the additional funds paid by Duke would constitute full payment for the work as outlined in the associated purchase order. (T 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. (T 10, p 130) Further, the Commission did not specifically review or consider the Asheville coal ash sale in prior fuel proceedings. (T 10, p 131) She testified that the cost of disposing of coal ash in a landfill would not be a sale and would not be recoverable under the fuel clause. (T 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. (T 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 coal ash. 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. (T 10, PS 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. (PS McGee Cross-Examination Exhibit 4)

In PS 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 Ms. 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 coal ash 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, Ms. McGee did not dispute that the deed to Brickhaven was recorded the day after the Master Contract was signed. She also admitted that managing coal ash is Charah's expertise. (T 10, p 144) Further, Ms. McGee acknowledged that it was necessary for the Company to pay Chatham County millions of dollars to send the Sutton ash 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. (T 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 coal ash to Charah once the coal ash is loaded in to truck or railcar at Sutton for transportation to Brickhaven, Ms. McGee acknowledged that the provision could also refer to the transfer of liability of the coal ash. (T 10, p 150)

During the confidential portion of witness McGee's cross-examination, several contracts were entered into the record. PS 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 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 T 10, pp 152-53) In the Master Contract, Charah is listed as the "Seller". (Confidential T 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 coal ash. (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 T 10, p 154) The Master Contract also had alternative pricing in the event the ash could not be transported to Brickhaven and instead had to be transported to the Anson County Landfill. (Confidential T 10, p 154) Ms. McGee testified that if this alternative been used, the costs associated with the Master Contract would not be recoverable under the fuel adjustment clause. (Confidential T 10, p 154)

PS 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 T 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 ash from Dan River was to be transported to the Maplewood Landfill Site, and the ash 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..." Ms. McGee testified that the costs associated with the Waste Management Master Contract 8324 should not be recoverable under the fuel clause. (Confidential T 10, pp 159-60)

PS McGee Confidential Cross-Examination Exhibit 10 is Purchase Order 1380566 dated September 25, 2015, authorizing Waste Management to transport ash from the Asheville Plant for disposal at R&B Landfill in Homer, Georgia. (Confidential T 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 T 10, p 162) Ms. McGee testified that the costs associated with the Purchase Order would not be eligible for recovery under the fuel adjustment clause. (Confidential T 10, p 163)

PS 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." PS 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 T 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 ash.

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 ash at Sutton, as well as Dan River, W. S. Lee, and Riverbend. (T 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. (T 17, p 42) The document also describes the key contract provisions that would apply to the work, regardless of disposal method. (T 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. (T 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 PS Kerin Cross-Examination 1. (T 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. (T 17, pp 44-45)

DEP seeks a to recover certain coal ash costs related to the excavation and movement of ash 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 coal ash constitutes a sale of a by-product produced in the generation process. We conclude elsewhere in this Order that the costs related to the excavation and movement of ash from Sutton to Brickhaven were unreasonable and imprudently incurred, and are not recoverable. However, even if the costs were recoverable, they would not be recoverable through the fuel adjustment clause, as the transaction between DEP and Charah reflected in the Master Contract for the excavation and movement of the Sutton Plant ash does not constitute a "sale of a by-product" under G.S. 62-133.2(a1)(9).

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 coal ash is a by-product produced in the generation process. The issue, then, 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 coal ash 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 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 does 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 re-use 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 re-use 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 coal ash 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 coal ash. The Company admitted both in data responses and during the evidentiary hearing that nothing in the Master Contract or its associated documents included pricing or discounts to account for a sale of the coal ash. It is undisputed that nothing in the bid documents, contracts, purchase orders, or change orders relating to the Master Contract assign any value to the coal ash to "net" against the cost of the services provided by Charah. The evidence shows that DEP and Charah knew how to assign a value to coal ash 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 coal ash from DEP or DEC, as applicable, at a price as set forth in the Work Orders. This Agreement formed the basis for the sale of coal ash at the Belews Creek and Marshall plants via Work Orders entered into by DEC and Charah on January 1, 2014.

The Commission finds and concludes that the most likely reason that no value was assigned to the Sutton coal ash is because it did not have any value. Pursuant to CAMA, the Company was obligated to excavate the coal ash at the Sutton Plant. Managing coal ash is Charah's expertise. Charah's subsidiary, Green Meadow, LLC, purchased the Brickhaven facility the day after the Master Contract was signed. Utilization of Brickhaven to dispose of the Company's coal ash required the Company to pay Chatham County millions of dollars and required the construction of a multi-million dollar liner and leachate collection system. Based on the evidence, the Commission finds and concludes that the Brickhaven facility was purchased to take the Sutton Plant's (and the Riverbend Plant's) coal ash, and was not purchased for real estate development in need of some type of fill material.

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 coal ash 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 coal ash to Charah once the coal ash is loaded in to truck or railcar at Sutton, indicating the coal ash had value. However, on cross-examination, she agreed that this language could be interpreted to mean the transfer of liability. 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 coal ash had value. On the contrary, the evidence supports just the opposite – that possession of the coal ash 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 coal ash. The Commission is not persuaded that inclusion of these provisions demonstrate that a sale of coal ash 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 coal ash 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 Ms. McGee admitted that the costs incurred under that contract should not be recoverable under the fuel clause, as the ash was to landfilled. The Commission finds that these provisions are boilerplate that do not support the conclusion that a sale of coal ash occurred.

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 ash excavation, transportation, and disposal services to DEP, not for a sale of DEP's coal ash to Charah. The Commission therefore finds and concludes that the costs associated with the Master Contract are not recoverable under the fuel adjustment clause.

EVIDENCE IN SUPPORT OF FINDINGS OF FACT AND CONCLUSIONS NOS. 53-55

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

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 authorizing it to defer, and recover through amortization, all the costs it had incurred in connection with major storms during 2016, including capital costs and a return on the unamortized balance, but excluding the $12.7 million included in its annual rates as storm cost expense pursuant to the Commission's general rate order in DEP's most recent rate case, Docket No. E-2, Sub 1023. The $12.7 million figure represented an average of the Company's annual storm expenses over a ten-year period.

In its comments on the Company's petition, the Public Staff did not object to DEP's recovery of a substantial portion of its 2016 storm costs, but contended that the amount of the Company's proposed deferral was unreasonably high. In an order issued on July 20, 2017, the Commission consolidated Docket No. E-2, Sub 1131 with this docket.

Company witness Bateman testified (T 6, pp 124-25, 203-04) 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. 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.

On cross-examination, witness Bateman acknowledged (T 7, pp 447-48) 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. She also acknowledged (T 7, p 452) 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.

Public Staff witness Maness testified (T 18, pp 321-22) 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. 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 reasoned, 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 (T 18, p 322) that "[h]istorically, the Commission has amortized storm damage expenses over spans of time ranging from 40 months to ten years." 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 ten-year period.

In addition, witness Maness noted (T 18, p 322) that in cases involving single-storm deferrals, the Commission has generally begun the amortization period in the month when the storm occurred. 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 her Settlement Testimony, Exhibit No. 2-1(b), Line 3, Public Staff 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.

On this issue the Commission is in agreement with witnesses Maness and Peedin. 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.

Finally, 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 (T 7, pp 427-28) 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. 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. It is widely accepted by economists that when a business is assured of recovering all its costs for a particular expense, its incentive to minimize its costs for that expense is significantly diminished. In light of this concern, the Commission has generally been reluctant to approve cost tracker systems, except when they are required by statute.

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, and the $52.752 million deferral proposed by witnesses Maness and Peedin is appropriate. We also find and conclude that since even the $52.752 million deferral is unusually large, the amortization period should also be longer than usual, and therefore we find that witness Peedin's proposed ten-year amortization period is appropriate. Finally, we conclude 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 begin in October 2016. Finally, 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.

EVIDENCE IN SUPPORT OF FINDINGS OF FACT AND CONCLUSIONS NOS. 56-58

The evidence supporting these findings of fact and conclusions is found in DEP's verified Application, DEP's Petition for Approval of Job Retention Rider, filed in Docket E-2, Sub 1153, the testimony of Company witness Wheeler, the testimony of Public Staff witness McLawhorn, the exhibits of witness Wheeler, and the entire record in this proceeding.

On August 14, 2017, DEP field a Petition for Approval of Job Retention Rider, in Docket E-2, Sub 1153. By Order dated August 29, 2017, the Commission consolidated this matter with the Sub 1142 general rate case. DEP's proposed JRR-1 was filed in accordance with the requirements and guidelines the Commission established in its Order Adopting Guidelines for Job Retention Tariffs (JRT Order) dated December 8, 2015, in Docket No. E-100, Sub 73.

In its Petition for Approval of the JRR (JRR Petition), the Company stated that the proposed JRR is intended to prevent the loss of industrial production and jobs from the Company's service area. It requested that the Commission take judicial notice of the Company' Initial and Reply Comments filed in the JRT Order docket where the Company outlined the conditions that led to the loss of industrial jobs. The Company further stated that it had spoken with representatives of the industrial customers to confirm that the customers still face the same economic challenges presented at the time of the JRT Order filings. In its JRR Petition, the Company stated that the JRR is in the public interest, will offer the opportunity to retain industrial jobs, will not unfairly disadvantage other customer classes, and complies with the existing law prohibiting unjust discrimination and undue preference.

In order to qualify for the JRR Rider, DEP's JRR Petition proposed that an eligible customer must do all of the following:

(1) Use electric power "as the principal motive power for the manufacture of a finished product, the extraction, fabrication or processing of a raw material, or the transportation of 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.

The JRR would not be available for services under outdoor lighting schedules, or for customers receiving certain rate discounts. To be eligible, customers must have an aggregate demand of greater than 3,000kW at all facilities in the service territory and a history of 12 months of service with the Company. The JRR would be available for a period of five years from the implementation of the Rider. In its JRR Petition, the Company stated the annual revenue impact of the JRR would be $24.8 million.

Public Staff witness McLawhorn testified that the Company's proposed JRR is not unduly discriminatory and is in the public interest. He stated that the JRR is designed to apply to large industrial customers and provides a balance of the benefits between the customers that will benefit from the rate reduction and the customers that will bear the costs of the reduction in revenues. Witness McLawhorn also stated that the Company demonstrated the need for the JRR in showing only slight growth in industrial sales after several years of decreasing sales to industrial customers. He testified that the proposed discounted revenue from the JRR participants would likely be greater than the marginal costs to serve participants. Public Staff witness McLawhorn disagreed with the Company's proposal for deferral accounting of the discounted revenue. The Public Staff proposed treating the revenue impact from the JRR in a manner similar to an adjustment made in other rate cases to account for customer migration between rate schedules. The Public Staff also recommended that the impact of the rate discount be recovered from all ratepayers, including the customers eligible for the rate discount.

In rebuttal testimony, Company witness Wheeler outlined further evidence of declining industrial sales, and the concern of industrial customers regarding their ability to compete globally in the face of rising electricity costs. He also provided an exhibit that identified a list of major manufacturing facilities that have closed in the Company's territory since 2014.

In the Stipulation, the Company and the Public Staff agreed that the JRR meets the JRT Guidelines adopted in the JRT Order, notwithstanding two areas of disagreement: whether pipeline customers should be eligible and whether the Company shareholders would contribute $3.5 million to the JRR recovery on an annual or one-time basis. The Stipulating Parties also agreed that the JRR would be recovered through a rider from all retail customers, subject to annual adjustment at the same time as the December fuel adjustment. The Parties further agreed the Company shall filed compliance tariffs prior to the implementation of the JRR Rider and notify customers by bill insert when the rider is implemented.

Pipeline Eligibility

DEP's proposed JRR provides, in part, that the JRR be available for customers that "use electric power as the principal motive power for the manufacture of a finished product, the extraction, fabrication or processing of a raw material, or the transportation or preservation of a raw material of a finished product."

Public Staff witness McLawhorn expressed concern in his testimony regarding DEP's proposal to extend eligibility for the JRR to companies involved in the "transportation or preservation of a raw material of a finished product." 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.

DEP witness Wheeler testified in his rebuttal testimony that while the disputed phase could apply to pipeline customers, it could also apply to other customers. (T 10, p 247) He stated that the Company believes it is appropriate to include pipeline customers in the availability of the JRR because these customers have expressed concerns with electricity costs.

In response to cross examination by counsel for CIGFUR, witness Wheeler noted that the JRT Order provided an example of an appropriate definition of customers that would be eligible for a proposed JRT. The definition, which was proposed by CIGFUR in the JRT Order proceeding, included the disputed phrase that provides eligibility for pipeline customers. (T 11, pp 29-31)

During cross examination by counsel for the North Carolina Justice Center et al., witness Wheeler noted that a pipeline could not relocate from the state, but could reduce the amount of gas flowing into the state or cease to operate. (T 11, p 70) 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.

<u>Cost Sharing</u>

In its JRR Petition, DEP proposed that it absorb $3.5 million of the cost of the JRR on a one-time basis. The Public Staff proposed that the Company contribute $3.5 million on an annual rather than one-time basis.

Public Staff witness McLawhorn testified that not only customers, but shareholders, benefit from the retention of industrial jobs and the load associated with the jobs. Therefore, a fair sharing of the revenue impact of the JRR would require the Company to contribute $3.5 million on an annual rather than one-time basis.

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. (T 6, p 19) DEP witness Wheeler testified in his rebuttal testimony that requiring shareholders to absorb the $3.5 million outside of a one-time contribution would deprive the Company of its opportunity to recover its costs. (T 10, p 250)

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. (T 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. (T 18, p 125)

The Company, as well as ratepayers, benefit from the retention of industrial jobs, and the load related to the retention of the industrial jobs. It is appropriate for the

Company to contribute to the JRR on an on-going basis, rather than making a one-time contribution.

Commission approval of the JRR is largely a question of public policy requiring the Commission to balance the costs and benefits to the company's ratepayers. The Commission initiated a separate proceeding, the JRT Order proceeding, in order to establish guideline and filing requirements for job retention tariffs. The Commission concludes the JRR was filed in accordance with the requirements and guidelines the Commission established in its JRT Order and should be approved as modified below.

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 "use electric power as the principal motive power for the manufacture of a finished product, the extraction, fabrication or processing of a raw material, or the transportation or preservation of a raw material of a finished product" should be removed from the eligibility criteria.

The Commission finds that North Carolina continues to experience a loss of industry and faces further loss of industrial sales. The JRR proposed by the Company, as modified by the Stipulation and by removing the eligibility of companies that operate gas pipelines, is not unduly discriminatory, is in the public interest, and is approved.

As discussed in regards to the sharing of costs related to coal ash costs, G.S. 62-133(d) provides that even where costs are reasonable, circumstances may justify the sharing of costs between ratepayers and shareholders to achieve just and reasonable rates. Because the JRR benefits both ratepayers and shareholders, the Commission finds that in order to achieve just and reasonable rates, an equitable sharing of the JRR costs should be implemented in the recovery of the costs of the JRR Rider. Therefore, the Company's recovery should be reduced by the amount of $3.5 million each year the JRR is in effect to recognize the benefit to shareholders of the JRR.

As provided in the Stipulation, The JRR revenue credits shall be recovered through a rider from all retail customers concurrent with the implementation of the JRR. The JRR Rider will be subject to annual adjustment at the time of the December fuel adjustment. The Company shall file compliance tariffs prior to the implementation of the JRR Rider and notify customers by bill insert when the rider is implemented.

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 shall be allowed to increase its rates and charges effective for service rendered as of ____ 1, 2018, so as to produce an increase in gross annual revenue for its North Carolina retail operations of $99.726 million for the first four years

the rates approved herein are in effect, and $142.303 million thereafter, based upon the adjusted test year level of operations, as set forth in this Order;

3. 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. ;

4. That the Company shall implement an increment rider, effective ___ 1, 2018, 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.

5. 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, by December 31, 2018;

6. The Company shall conduct a workshop on its Power/Forward grid investments in the second quarter of 2018;

7. That the aspects of rate design agreed upon in the Stipulation are approved and shall be implemented;

8. That the Company shall increase its BCC for Schedule RES to $14.00 per month and the BCCs for Schedules R-TOUD, R-TOUE, and R-TOU to $16.85 per month;

9. That within 30 days of this Order, but no later than ten 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;

10. 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; and

11. That the Company shall file annual cost of service studies based on both the SCP and SWPA methodologies.

This ____ day of ____________, 2018.

THE NORTH CAROLINA UTILITIES COMMISSION

M. Lynn Jarvis, Chief Clerk