STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-22, SUB 562
DOCKET NO. E-22, SUB 566

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-22, SUB 562 In the Matter of Application of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina DOCKET NO. E-22, SUB 566 In the Matter of Petition of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina for an Accounting Order to Defer Certain Capital and Operating Costs Associated with Greensville County Combined Cycle Addition	)	ORDER ACCEPTING PUBLIC STAFF STIPULATION IN PART, ACCEPTING CIGFUR STIPULATION, DECIDING CONTESTED ISSUES, AND GRANTING PARTIAL RATE INCREASE

HEARD: Tuesday, July 30, 2019, at 7:00 p.m., Halifax County Historical Courthouse, 10 N. King Street, Commissioners' Meeting Room, Halifax, North Carolina

Wednesday, July 31, 2019, at 7:00 p.m., Martin County Courthouse, 305 E. Main Street, Williamston, North Carolina

Wednesday, August 7, 2019, at 7:00 p.m., Dare County Courthouse, 962 Marshall Collins Drive, Manteo, North Carolina

Monday, September 23, 2019, at 2:00 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chair Charlotte A. Mitchell, Presiding; Commissioners ToNola D. Brown-Bland, Lyons Gray, and Daniel G. Clodfelter

APPEARANCES:

For Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina:

Mary Lynne Grigg, Andrea R. Kells, and W. Dixon Snukals, 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

For Carolina Industrial Group for Fair Utility Rates I:

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

For Nucor Steel–Hertford:

Joseph W. Eason, Nelson, Mullins, Riley & Scarborough, LLP, 4140 Park Lake Avenue, Suite 200, Raleigh, North Carolina 27612

Damon E. Xenopoulos, Stone Mattheis Xenopoulos & Brew, PC, 1025 Thomas Jefferson Street, NW, Washington, D.C. 20007-5201

For the Attorney General's Office:

Jennifer Harrod, Special Deputy Attorney General, Theresa Townsend, Special Deputy Attorney General, and Margaret A. Force, Assistant Attorney General, North Carolina Attorney General's Office, Department of Justice, 114 West Edenton Street, Raleigh, North Carolina 27603

For the Using and Consuming Public:

David Drooz, Chief Counsel, Dianna Downey, Staff Attorney, Gina Holt, Staff Attorney, Lucy Edmondson, Staff Attorney, Heather Fennell, Staff Attorney, and Layla Cummings, Staff Attorney, North Carolina Utilities Commission – Staff, Legal Division, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On February 27, 2019, pursuant to Commission Rule R1-17(a), Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (DENC or the Company) filed a Notice of Intent to File General Rate Application in Docket No. E-22, Sub 562.

On March 1, 2019, Carolina Industrial Group for Fair Utility Rates I (CIGFUR) filed a Petition to Intervene. The Petition was granted by the Commission on March 7, 2019.

On March 25, 2019, Nucor Steel–Hertford (Nucor) filed a Petition to Intervene. The Petition was granted by the Commission on March 29, 2019.

On March 29, 2019, DENC filed an Application for a general rate increase pursuant to N.C. Gen. Stat. §§ 62-133 and 62-134 and Commission Rule R1-17 (Application) along with a Rate Case Information Report – Commission Form E-1 (Form E-1) and the direct testimony and exhibits of Mark D. Mitchell – Vice President, Generation Construction; Richard M. Davis – Director of Corporate Finance and Assistant Treasurer; Robert B. Hevert – Managing Partner at ScottMadden, Inc.; Bruce E. Petrie – Manager of Generation System Planning; Jason E. Williams – Director of Environmental Services; Paul M. McLeod – Regulatory Specialist; Robert E. Miller – Regulatory Analyst; Paul B. Haynes – Director of Regulation; and Bobby E. McGuire – Director of Electric Transmission Project Development & Execution. Also on March 29, 2019, DENC filed an application for an accounting order to defer certain capital and operating costs associated with its Greensville County Power Station (Greensville CC) in Docket No. E-22, Sub 566. The Company also requested that the Commission consolidate its consideration of the deferral application with the Company's application for a general rate increase in Docket No. E-22, Sub 562.

On April 29, 2019, the Commission issued an Order Declaring General Rate Case and Suspending Rates.

On May 2, 2019, the Commission issued an Order Consolidating Dockets, which consolidated this general rate case with DENC's pending petition for deferral accounting authority to defer post-in-service costs associated with commercial operation of the Greensville County CC in Docket No. E-22, Sub 566.

On May 30, 2019, the Commission issued an Order Scheduling Investigation and Hearings, Establishing Intervention and Testimony Due Dates and Discovery Deadlines, and Requiring Public Notice.

On August 5, 2019, DENC filed supplemental direct testimony and exhibits of witnesses Davis, McLeod, Miller, Haynes, Petrie, and Deanna R. Kesler – Regulatory Consultant in Demand-Side Planning, as well as applicable supplemental Form E-1 information report items and supplemental Commission Rule R1-17 information.

On August 14, 2019, DENC filed additional supplemental direct testimony and exhibits of witness Haynes.

On August 15, 2019, DENC filed affidavits of publication evidencing proof of publication of notice.

On August 23, 2019, the North Carolina Utilities Commission – Public Staff (Public Staff) filed the testimony and exhibits of Sonja R. Johnson – Accountant; David M. Williamson – Utilities Engineer; Jack L. Floyd – Utilities Engineer; Michelle M. Boswell – Staff Accountant; Tommy C. Williamson – Utilities Engineer; Roxie McCullar – Consultant at William Dunkel and Associates; Dr. J. Randall Woolridge – Consultant; Jeffrey T. Thomas – Utilities Engineer; Michael C. Maness – Director of the Accounting Division; and Jay B. Lucas – Utilities Engineer. Also on August 23, 2019, Nucor filed the testimony and exhibits of Paul J. Wielgus and Jacob M. Thomas, and CIGFUR filed the testimony and exhibits of Nicholas Phillips, Jr.

On August 27, 2019, the North Carolina Attorney General's Office (AGO) filed a Notice of Intervention.

On August 28, 2019, the Commission issued an Order Requesting Additional Information.

On September 12, 2019, DENC filed second supplemental direct testimony and exhibits of witness McLeod, supplemental Form E-1 items, and supplemental Commission Rule R1-17 information. Also on September 12, 2019, DENC filed the rebuttal testimony and exhibits of witnesses Davis, Hevert, McLeod, Miller, Haynes, and Williams.

On September 16, 2019, the Commission issued an Order Providing Notice of Commission Questions. Also on September 16, 2019, DENC filed its Witness List.

On September 17, 2019, DENC filed an Agreement and Stipulation of Partial Settlement with the Public Staff (Public Staff Stipulation). Also on September 17, 2019, the Public Staff filed Partial Settlement Joint Testimony of witnesses Johnson and James S. McLawhorn – Director, Electric Division, and DENC filed testimony of witnesses Davis, Hevert, McLeod, Miller, and Haynes in support of the Public Staff Stipulation.

On September 18, 2019, the Public Staff filed supplemental testimony of witness Maness. Also on September 18, 2019, the Public Staff filed exhibits and supporting schedules for the joint testimony of witnesses McLawhorn and Johnson previously filed on September 17, 2019.

On September 19, 2019, DENC and the Public Staff filed a joint motion to excuse several of their witnesses, and CIGFUR filed a motion to excuse its witness. The motions were granted on September 23, 2019.

On September 23, 2019, DENC filed an Agreement and Stipulation of Settlement with CIGFUR (CIGFUR Stipulation). Also on September 23, 2019, DENC filed a Revised Witness List and Late Filed Exhibits in response to the Commission's Order Providing Notice of Commission Questions.

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

Halifax: Tony Burnette, Dean Knight, Chuck Overton, and Silverleen Alston.

Williamston: John Liddick, Patrick Flynn, Tommy Bowen, James Wiggins, and Glenda Barnes.

Manteo: Rhett White, Manny Medeiros, John Windley, and Brad Bernard.

Raleigh: No public witnesses appeared.

The Commission received numerous consumer statements of position in this matter. All public witness testimony and consumer statements of position have been considered by the Commission and made a part of the record.

The matter came on for expert witness hearing on September 23, 2019. DENC presented the testimony of witnesses Mitchell, Davis, Hevert, McLeod, Haynes, Miller, and Williams. The testimony and exhibits of DENC witnesses McGuire, Kessler, and Petrie were stipulated into the record. The testimony and exhibits of Nucor witnesses Thomas and Wielgus were stipulated into the record. The testimony and exhibits of CIGFUR witness Phillips were stipulated into the record. The Public Staff presented the testimony of witnesses Maness, Johnson, and McLawhorn. The testimony and exhibits of Public Staff witnesses David Williamson, Floyd, Boswell, Tommy Williamson, McCullar, Woolridge, and Thomas were stipulated into the record.

The pre-filed testimony of those witnesses who testified at the expert witness hearing, as well as the pre-filed testimony of all other witnesses filing testimony in this docket, was copied into the record as if given orally from the stand, and their pre-filed exhibits were admitted into evidence.

The Public Staff and DENC filed late-filed exhibits and responses to Commission questions on September 23, September 26, September 27, October 1, October 2, October 7, October 8, and October 23, 2019.

On November 6, 2019, DENC and the Public Staff filed a Joint Proposed Order on the issues covered by the Public Staff Stipulation and separate proposed orders on the issues of cost recovery for coal combustion residuals. Post-hearing briefs were filed by DENC, the AGO, CIGFUR, and Nucor.

The above is a summary of the main filings and proceedings in this docket. Additional filings made by the parties and orders issued in this proceeding are not discussed in this Order but are included in the record.

Based on the entire record in this proceeding, the Commission makes the following

FINDINGS OF FACT

Jurisdiction

1. Virginia Electric and Power Company (VEPCO) is duly organized as a public utility operating under the laws of the State of North Carolina as Dominion Energy North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. DENC is engaged in the business of generating, transmitting, distributing, and selling electric power and energy to the public in North Carolina for compensation. DENC is an unincorporated division of VEPCO and has its office and principal place of business in Richmond, Virginia. VEPCO is a wholly-owned subsidiary of Dominion Energy, Inc. (DEI).

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

3. DENC is lawfully before the Commission based upon its application for a general increase in its retail rates pursuant to N.C.G.S. §§ 62-133, 62-133.2, 62-134, and 62-135, and Commission Rule R1-17.

4. The appropriate test period for use in this proceeding is the 12 months ended December 31, 2018, adjusted for certain known changes in revenue, expenses, and rate base.

The Application

5. In summary, by its general rate case Application, supporting testimony, and exhibits filed on March 29, 2019, and on subsequent dates during the proceeding, DENC sought an increase in its non-fuel base rates and charges to its North Carolina retail customers of $26,958,000, along with other relief, including cost deferrals and changes to its rate design. The Application was based upon a requested rate of return on common equity of 10.75%, an embedded long-term debt cost of 4.451%, and DENC’s actual capital structure of 53.01% common equity and 46.99% long-term debt, as of December 31, 2018. DENC submitted supplemental filings and testimony after its initial Application and the effect of the Company’s supplemental filings was to change its proposed annual base non-fuel revenue requirement to a $24,195,000 increase in annual revenue.

Stipulation with Public Staff

6. On September 17, 2019, DENC and the Public Staff (Stipulating Parties) entered into and filed the Public Staff Stipulation, resolving all of the issues in this

proceeding among the Stipulating Parties, except for issues associated with coal combustion residuals (CCR) costs.

7. The Public Staff Stipulation is the product of give-and-take in settlement negotiations between the Stipulating Parties, and it is material evidence entitled to be given appropriate weight by the Commission.

Stipulation with CIGFUR

8. On September 23, 2019, DENC and CIGFUR entered into and filed the CIGFUR Stipulation, resolving rate of return and certain cost allocation, rate design, and terms and conditions issues in this proceeding.

9. The CIGFUR Stipulation is the product of give-and-take in settlement negotiations between DENC and CIGFUR, and it is material evidence entitled to be given appropriate weight by the Commission.

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

10. The capital structure set forth in Section III.A of the Public Staff Stipulation, consisting of 52.00% common equity and 48.00% long-term debt, is reasonable and appropriate for use by DENC in this case.

11. The embedded cost of debt set forth in Section III.A of the Public Staff Stipulation of 4.442% is reasonable and appropriate for use by DENC in this case.

12. The rate of return on common equity that the Company should be allowed the opportunity to earn in this docket is 9.75%, as set forth in Section III.A of the Public Staff Stipulation and is reasonable and appropriate for use in this docket.

13. The overall rate of return that the Company should be allowed the opportunity to earn on the cost of the Company's used and useful property is 7.20%, as set forth in Section III.A of the Public Staff Stipulation and is reasonable and appropriate for use in this docket.

14. The authorized levels of overall return and rate of return on common equity set forth above are supported by competent, material, and substantial record evidence, are consistent with the requirements of N.C.G.S. § 62-133 in light of changing economic conditions and will allow the Company to maintain its facilities and services in accordance with the reasonable requirements of the Company's customers.

15. With respect to the foregoing findings on the appropriate overall rate of return on rate base and allowed rate of return on common equity for use in this proceeding, the Commission makes the following more specific findings of fact:

a. The overall rate of return on rate base and allowed rate of return on common equity underlying DENC's current base rates are 7.367% and 9.90%, respectively.[1]

b. DENC's current base rates became effective for service rendered on and after January 1, 2017, and have been in effect since that date.

c. In its Application, DENC sought approval for rates which were based on an overall rate of return on rate base of 7.79% and an allowed rate of return on common equity of 10.75%.

d. As set forth in the Public Staff Stipulation, the Stipulating Parties seek approval of an overall rate of return on rate base of 7.20% and an allowed rate of return on common equity of 9.75%.

e. The reduction in overall rate of return on rate base and rate of return on common equity from both DENC's existing base rates and the Application, as reflected in the Public Staff Stipulation, is a substantial economic benefit to DENC's customers.

f. As reported by Regulatory Research Associates (RRA), the median rate of return on equity authorized for vertically integrated electric utilities during the first half of 2019 was 9.73% (compared to 9.75% in 2018). The authorized rate of return on equity for vertically integrated electric utilities is in the top third of all jurisdictions rated by RRA in terms of constructive, and less risky regulatory environments range from 9.37% to 10.55%, with a mean of 9.93% and a median of 9.95% from 2016 through early September of 2019.

g. The stipulated rate of return on common equity of 9.75% is equal to the lowest rate of return on common equity granted by the Commission for a major electric utility in the last ten years.

h. The currently authorized rate of return on common equity underlying the base rates of Public Service Company of North Carolina, Inc. (PSNC), and Piedmont Natural Gas Company, Inc. (Piedmont), is 9.70%.[2] The currently

[1] Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions, *Application by Virginia Electric and Power Co., d/b/a Dominion North Carolina Power for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-22, Sub 532 (N.C.U.C. Dec. 22, 2016) (DENC Sub 532 Order).

[2] Order Approving Rate Increase and Integrity Management Tracker, *Application of Public Service Co. of North Carolina, Inc., for a General Increase in its Rates and Charges*, No. G-5, Sub 565 (N.C.U.C. Oct. 28, 2016) (PSNC Sub 565 Order); Order Approving Stipulation, Granting Partial Rate Increase,

authorized rate of return on common equity for Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP), is 9.90%.[3]

i. The stipulated allowed rate of return on common equity of 9.75% is consistent with the rates of return on common equity identified above.

j. The stipulated overall rate of return on rate base of 7.20% and rate of return on common equity of 9.75% are supported by competent, material, and substantial evidence.

k. The evidence indicates that the overall economic climate in North Carolina (and nationally) remains strong, including data and projections from reliable sources that demonstrate: (i) generally consistent with the national rate of unemployment, the rate of unemployment in North Carolina has fallen by 8.30 percentage points since its peak in late 2009 and early 2010 to 3.70% by December 2018; (ii) unemployment in the DENC counties peaked in late 2009 – early 2010 at 13.41% and had fallen to 4.95% by December 2018; growth in the Gross Domestic Product (GDP) is relatively strongly correlated between North Carolina and the national economy, and it has been growing at a moderate pace since 2016; (iii) median household income in North Carolina has grown since 2009 at an annual rate of 2.32%; and (iv) residential electric rates in North Carolina since 2018 remain approximately 13% below the national average.

l. Irrespective of the economic conditions being experienced in North Carolina at this time, which are positive, some customers of DENC will struggle to pay their utility bills under the rate increases authorized herein.

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

n. The rate of return on common equity and capital structure approved by the Commission appropriately balances the benefits received by DENC's customers from DENC's provision of safe, adequate, and reliable electric service in support of businesses, jobs, hospitals, government services, and the

Line 434 Revenue Rider, EDIT Riders, Provisional Revenues Rider, and Requiring Customer Notice, *Application of Piedmont Natural Gas Co., Inc., for an Adjustment of Rates, Charges, and Tariffs Applicable to Service in North Carolina, Continuation of its IMR Mechanism, Adoption of an EDIT Rider, and Other Relief*, No. G-9, Sub 743 (N.C.U.C. Oct. 31, 2019) (PNG Sub 743 Order).

[3] Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, *Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-7, Sub 1146 (N.C.U.C. June 22, 2018), *appeal docketed*, No. 401A18 (N.C. Nov. 7, 2018) (DEC Sub 1146 Order); Order Accepting Stipulations, Deciding Contested Issues and Granting Partial Rate Increase, *Application by Duke Energy Progress, LLC, For Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1142 (N.C.U.C. Feb. 23, 2018), *appeal docketed*, No. 401A18 (N.C. Nov. 7, 2018) (DEP Sub 1142 Order).

maintenance of a healthy environment with the difficulties that some of DENC's customers will experience in paying the Company's increased rates.

16. The capital structure and rates of return on rate base and common equity set forth in the Public Staff Stipulation and the CIGFUR Stipulation result in a cost of capital which appropriately balances DENC's interest in maintaining both its credit ratings and its ability to obtain equity financing on reasonable terms, and its customers' interest in receiving electric utility service at the lowest possible rate.

Adjustments to Cost of Service

17. The Public Staff Stipulation provides for certain accounting adjustments, which are set forth in detail at Settlement Exhibit I. The Stipulating Parties agree that the settlement regarding those issues will not be used as a rationale for future arguments on contested issues brought before the Commission. The accounting adjustments outlined in Settlement Exhibit I, except line No. 18 pertaining to Chesterfield Units 3 and 4, are just and reasonable to all parties in light of all the evidence presented.

18. The Company's updates through June 30, 2019, to certain revenues, expenses, and investments, as agreed to and adjusted in the Public Staff Stipulation, are appropriate for use in this proceeding.

19. DENC's pro forma inclusion in rates of the full cost of service of the Greensville combined cycle generating plant (Greensville CC), which began commercial operation on December 8, 2018, is appropriate, with the exception of the non-fuel O&M expenses for displacement adjustment, as discussed below.

20. DENC's request to defer the costs associated with the Greensville CC from the time the unit was placed into service until placement in base rates in this rate case is appropriate. Amortization over a three-year period beginning with the effective date of new rates in this proceeding is also appropriate.

21. The Public Staff Stipulation provides that an adjustment of $81,000 should be made to storm restoration costs to reflect the use of a ten-year historical average of these costs. This provision of the Public Staff Stipulation is just and reasonable to all parties in light of all the evidence presented.

22. The Stipulating Parties have agreed to a reduction in revenue requirement of $142,000 for the variable non-fuel O&M expenses displacement. This agreed upon adjustment is to reflect the updated and corrected purchased energy and electric test year output numbers, and it is just and reasonable to all parties in light of the evidence presented.

23. The Public Staff's adjustment to remove the costs of the Skiffes Creek project mitigation is appropriate as provided for in the Public Staff Stipulation.

24. The Public Staff Stipulation provides that 50% of the Mount Storm impairment costs should be removed, with the remaining portion amortized over 2.75 years. This provision of the Public Staff Stipulation is just and reasonable to all parties in light of all of the evidence presented.

25. The Stipulating Parties have agreed to reduce the revenue requirement by $720,000 to reflect the updated, actual costs of the Company's new office building (DES Office). In light of the evidence presented, this adjustment is just and reasonable to all parties.

26. As set forth in Section IV.S of the Public Staff Stipulation, the Stipulating Parties have agreed that the Company's depreciation rates will be set based on the rates set forth in the Company's Application. Subject to Findings of Fact Nos. 56-58 and the discussion thereunder, this provision of the Public Staff Stipulation is just and reasonable to all parties in light of all of the evidence presented.

Federal Excess Deferred Income Taxes

27. The Company is adjusting rates to pass along to North Carolina jurisdictional customers the benefit of federal excess deferred income taxes (EDIT) resulting from the Federal Tax Cuts and Jobs Act of 2017 (Tax Act). The system-level federal EDIT balance as of December 31, 2017, was $2.0 billion, of which $94.7 million was allocable to the North Carolina retail jurisdiction.

28. The Public Staff Stipulation provides that DENC will implement an increment rider, Rider EDIT, to allow for the recovery by DENC of federal EDIT of $1,214,000 (on a pre-income tax basis). This amount includes all unprotected federal EDIT allocable to the North Carolina jurisdiction totaling approximately $8.0 million, partially offset by the refund to ratepayers of approximately $6.8 million associated with North Carolina jurisdictional federal EDIT amortization attributable to the 22-month period of January 1, 2018, through October 31, 2019.

29. DENC should implement Rider EDIT to recover certain federal EDIT from customers over a two-year period on a levelized basis, with a return. As reflected on Settlement Exhibit II, Schedule 2, the appropriate amount to be recovered from customers is a total of $1,299,369. Rider EDIT should be calculated and reviewed using the methodology presented in the testimony of DENC witness Haynes.

30. The Company's fully-adjusted cost of service includes the income tax benefit arising from the annual amortization of federal protected EDIT during the test year, thereby incorporating a going-level of federal protected EDIT amortization in base non-fuel rates.

31. The ratemaking treatment of federal EDIT, including Rider EDIT as set forth in the Public Staff Stipulation, is just and reasonable to all parties in light of all of the evidence presented.

Base Fuel Factor

32. The Public Staff Stipulation provides for a total decrease in DENC's annual base fuel revenues of $2.155 million from its North Carolina retail electric operations, based on a jurisdictional average base fuel factor of 2.092¢/kWh (including regulatory fee), which is just and reasonable to all parties in light of all the evidence presented.

33. The jurisdictional average base fuel factor should be voltage-differentiated between customer classes, as provided on Company Additional Supplemental Exhibit PBH-1, Schedule 1, Page 2.

34. The Company has proposed to adjust its base fuel and non-fuel expenses to reflect 71% as a proxy for the fuel cost component of energy purchases for which the actual fuel cost is unknown (Marketer Percentage), with the remaining 29% of the cost of energy purchases being recovered by DENC in base rates. This represents a reduction from the Company's current Marketer Percentage of 78%. The 71% Marketer Percentage is reasonable and appropriate for use in this proceeding and shall remain in effect until the Company's 2021 annual fuel factor filing or next general rate case, whichever comes first.

Cost of Service Allocation Methodology

35. The Public Staff and CIGFUR Stipulations provide for the use of the Summer-Winter Peak and Average (SWPA) methodology calculated using the system load factor to weight the average component and (1 – system load factor) to weight the peak demand component to allocate the Company's cost of service to the North Carolina jurisdiction and among the customer classes in this case. The Stipulating Parties and CIGFUR agree that use of the SWPA methodology for allocation between jurisdictions and among customer classes shall not be a precedent for, and may be contested in, future general rate case proceedings. The Stipulating Parties further agree that the Company's proposed adjustments (1) to DENC's recorded summer and winter peaks to recognize the peak demand contributions of non-utility generators (NUGs) interconnected to the Company's distribution system, and (2) to remove the demand and energy requirements of three customers, one wholesale customer North Carolina Electric Membership Corporation (NCEMC), and two large industrial customers in the Company's Virginia jurisdiction for whom the obligation to provide generation service has ended or will end during 2019 are appropriate and reasonable. The SWPA cost of service methodology, adjusted as described, is appropriate for determining the Company's North Carolina jurisdictional and retail customer class cost allocation and responsibility for purposes of this case.

36. DENC's adjustment to the peak component of SWPA appropriately recognizes the impact that NUGs have on DENC's utility system and is appropriate for use in this proceeding.

37. DENC's adjustment to remove the demand and energy requirements of customers whose service has ended or will end during 2019 is appropriate for use in this proceeding.

38. The SWPA cost of service methodology, as adjusted by DENC, has been used in this Order to determine the appropriate levels of rate base, revenues, and expenses for North Carolina retail service.

39. DENC's continued use of the SWPA methodology in this proceeding properly assigns production plant costs to all customer classes, including the Schedule NS Class, in recognition of its significant use of the Company's generation throughout the year.

Rate Design

40. 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 should be consistent with the principles described in the testimony of Public Staff witness Floyd and the rate design presented by Company witness Haynes in his direct testimony, as adjusted by and as referenced in Section VI of the Public Staff Stipulation, which are reasonable, appropriate, and nondiscriminatory. The Public Staff Stipulation further provides that in developing rates based upon the foregoing class apportionment, the Company should consider the rate of return indices for the LGS and 6VP classes and an appropriate rate of return index for the Schedule NS class. Finally, the Public Staff Stipulation provides that all classes should share in the total base revenue increase. The rate design principles proposed by the Company, as filed revised by the Public Staff Stipulation, are just and reasonable.

Service Regulations, Vegetation Management, and Quality of Service

41. The amendments to the service regulations proposed by the Company are reasonable.

42. The vegetation management plan of the Company is reasonable.

43. The overall quality of service provided by DENC is good.

Conversion Costs of Chesterfield Power Station Units 3 and 4

44. The resolution of the recovery of the CCR wet to dry CCR handling conversion costs incurred by DENC at the Chesterfield Power Station (Chesterfield) Units 3 and 4, as set forth in Section VII.A of the Public Staff Stipulation, is not approved.

45. DENC's decision to incur wet to dry CCR handling conversion costs for Chesterfield Units 3 and 4 was not reasonable and prudent.

46. DENC should not be allowed to recover from North Carolina retail ratepayers the jurisdictional costs arising from the wet to dry CCR conversion project for Units 3 and 4 at Chesterfield.

Acceptance of Stipulations

47. Based upon all of the evidence in the record, including consideration of the public witness testimony and the evidence from parties who have not agreed with the Public Staff and CIGFUR Stipulations, with the exception of Section VII.A of the Public Staff Stipulation and subject to in Findings of Fact Nos. 56-58 and the discussion thereunder relating to the costs of removal portion of depreciation allowance, the provisions of the Stipulations are just and reasonable to the customers of DENC and to all parties to this proceeding, and serve the public interest. Therefore, the Stipulations should be approved in their entirety, with the exception of Section VII.A of the Public Staff Stipulation and subject to the Findings of Fact Nos. 56-58 and the discussion thereunder relating to the costs of removal portion of depreciation allowance. In addition, the Stipulations are entitled to substantial weight and consideration in the Commission's decision in this docket.

48. The base non-fuel and base fuel revenues provided in and resulting from the Public Staff and CIGFUR Stipulations, with the exception of Section VII.A of the Public Staff Stipulation, are just and reasonable to the customers of DENC, to DENC, and to all parties to this proceeding, and serve the public interest.

Recovery of CCR Costs

49. Since its last rate case, on a North Carolina retail jurisdictional basis, from the period beginning July 1, 2016 and running through June 30, 2019 (the Deferral Period), DENC has incurred $21.8 million in costs associated with the management of CCRs (the CCR Costs). The $21.8 million includes: (1) $19.2 million in expenditures made during the Deferral Period to comply with federal and state environmental regulations associated with managing CCRs and converting or closing waste ash management facilities at seven of DENC's generation stations; and (2) $2.7 million in financing costs incurred during the Deferral Period.

50. The record includes substantial evidence that, particularly where CCRs were being managed in lined landfills, the CCR Costs incurred during the Deferral Period were prudently incurred.

51. Although the Public Staff offered evidence challenging the manner in which DENC had managed CCRs and its various CCR waste management facilities over several decades, insofar as the specific CCR Costs incurred during the Deferral Period are concerned, while the record contains evidence that identifies instances of imprudence, the record contains insufficient evidence to permit the Commission to quantify the effects of imprudent actions on ratepayers.

52. DENC is entitled to recover the CCR Costs established in this general rate case, in the manner and subject to the conditions as set forth herein.

Ratemaking Treatment of Recoverable CCR Costs

53. Just and reasonable rates will be achieved by excluding from rate base the CCR Costs and amortizing recovery of the CCR Costs over a period of ten years.

54. It is reasonable, based on the evidence in the record in this proceeding, for DENC to recover its financing costs on the CCR Costs incurred during the Deferral Period, up to the effective date of rates approved pursuant to this Order, calculated at the Company's previously authorized weighted average cost of capital.

55. It is reasonable, based on the evidence in the record in this proceeding for annual compounding to be used in calculating the financing costs of deferred costs, including the CCR Costs, during the Deferral Period.

Accounting for CCR Remediation and Closure Costs

56. DENC did not account for CCR remediation costs as costs of removal in computing and requesting recovery of its allowance for depreciation expense.

57. DENC's failure to incorporate costs of remediation and closure of CCR waste management facilities as part of its allowance for depreciation expense is contrary to accepted depreciation expense accounting principles.

58. It is appropriate to require DENC to properly account for costs of remediation and closure of CCR waste management facilities as part of costs of removal included in its allowable depreciation expense.

CCR Insurance Claims

59. DENC should be required to take reasonable and prudent actions to pursue claims for insurance coverage of CCR remediation costs, where justified by DENC's insurance policy coverage.

60. All insurance proceeds received or recovered by DENC from the existing and potential CCR insurance claims should be placed in a regulatory liability account until the Commission enters an order directing DENC as to the appropriate disbursement of the proceeds. The regulatory liability account should accrue a carrying charge at the net-of-tax overall rate of return authorized for DENC in this Order.

61. Within ten days of the resolution of any of DENC's CCR insurance claims, whether by settlement, judgment or otherwise, DENC should file a report with the Commission explaining the result and stating the amount of insurance proceeds to be

received or recovered by DENC. This reporting requirement should apply even if there is litigation that is appealed to a higher court.

62. If meritorious concerns are raised by any party or by the Commission regarding the reasonableness of DENC's efforts to obtain an appropriate amount of recovery from the CCR insurance claims, DENC should bear the burden of proving that it exercised reasonable care and made prudent efforts to obtain the maximum recovery from the insurance claims.

Accounting for Deferred Costs

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

Revenue Requirement

64. After giving effect to the Commission's partial approval of the Public Staff Stipulation and full approval of the CIGFUR Stipulation, and the Commission's decisions on contested issues, the annual revenue requirement for DENC will allow the Company a reasonable opportunity to earn the rate of return on its rate base.

65. As soon as practicable following the issuance of this Order, DENC should calculate and file the annual revenue requirement with the Commission, consistent with the findings and conclusions of this Order. The Company should work with the Public Staff to verify the accuracy of the filing. DENC should file schedules summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determinations in this proceeding. DENC should provide the Commission with electronic copies of the filing, complete with formulas intact.

Just and Reasonable Rates

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

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

The evidence supporting these findings of fact and conclusions is contained in the verified Application and Form E-1 of DENC, 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. In addition, the Commission finds and concludes that the Company's use of a test period of the 12 months ended December 31, 2018, with appropriate adjustments for certain known changes in revenue, expenses, and rate base, comports with the requirements of N.C.G.S. § 62-133 and Commission Rule R1-17, and is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

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

Summary of the Evidence

On February 27, 2019, pursuant to Commission Rule R1-17(a), DENC filed notice of its intent to file a general rate case application.

On March 29, 2019, DENC filed its Application and initial direct testimony and exhibits, seeking a net increase of $26,958,000 in its annual base non-fuel rate revenue from its North Carolina retail electric operations. The Application is based on a requested rate of return on common equity of 10.75%, an overall rate of return of 7.79%, an embedded long-term debt cost of 4.451%, and DENC's actual capital structure of 53.01% common equity and 46.99% long-term debt, as of December 31, 2018. Further, the Application states that DENC's 2018 return on equity was 7.52% and its overall rate of return was 6.08%.

The Company's last general rate case was in 2016 in Docket No. E-22, Sub 532 (2016 Rate Case or Sub 532). By Order issued on December 22, 2016, the Commission approved an increase in DENC's base non-fuel revenues of $34,732,000, and a decrease of $8,942,000 in its base fuel revenues. DENC's current authorized rate of return on common equity is 9.9%, its authorized overall rate of return is 7.367%, and its authorized capital structure for ratemaking purposes is 51.75% common equity and 48.25% long-term debt. On March 4, 2019, the Commission approved a base non-fuel revenue reduction of $14,349,000 in Docket No. E-22, Sub 560, due to the net reduction in the Company's revenue requirement (i.e., the income tax expense component in then-current base rates) associated with the reduction in the federal corporate income tax rate pursuant to the Federal Tax Cuts and Jobs Act of 2017.

In its present Application, the Company proposed to implement the non-fuel base rate increase on a temporary basis subject to refund effective on November 1, 2019, along with an accelerated implementation of its new lower base fuel rate – to be filed in August 2019 – as part of any temporary rates (subject to refund) proposed to become effective November 1, 2019. The Company also proposed a methodology for returning certain federal EDIT to customers through a decrement rider, Rider EDIT, over a one–

year period. Further, DENC proposed to amortize the post-in-service costs of the Greensville CC it had requested to defer in Docket No. E-22, Sub 566.[4]

In its supplemental testimony filed on August 5, 2019, DENC updated the increase sought in its non-fuel base rates and charges to its North Carolina retail customers to $24.9 million.

In its second supplemental testimony filed on September 12, 2019, DENC updated the increase sought to $24.2 million.

Discussion and Conclusion

The Commission finds and concludes that DENC's Application satisfies the requirements of N.C.G.S. § 62-133, et seq., and Commission Rule R1-17. Further, DENC is a public utility within the meaning of N.C.G.S. § 62-3(23). Therefore, pursuant to N.C.G.S. § 62-30, et seq., the Commission has jurisdiction to consider and decide DENC's Application for a rate increase and other relief.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-7

The evidence supporting these findings of fact and conclusions is contained in the testimony of DENC witnesses Davis, McLeod, Hevert, Miller, and Haynes; Public Staff witnesses McLawhorn and Johnson; and the entire record in this proceeding.

Summary of the Evidence

On September 17, 2019, the Stipulating Parties filed the Public Staff Stipulation resolving all issues except the recovery of the Company's CCR costs. The Public Staff Stipulation is based on the same test period as the Company's Application. In summary, the Public Staff Stipulation provides:

- the revenue requirement increase of $24,879,000 proposed by the Company in its August 5, 2019, supplemental filing should be reduced by at least $13,517,000, based on the Company's position of an increase in the revenue requirement of $6.428 million, consisting of an increase of $8.583 million in non-fuel revenues and a decrease of $2.155 million in base fuel revenues, and the Public Staff's position of an increase in the revenue requirement of $2.037 million, consisting of an increase in $4.192 million in non-fuel revenues and a decrease of $2.155 million in base fuel revenues, with the difference between the Company's and the Public Staff's positions resulting from the unresolved issues identified in Section II.A.i of the Public Staff Stipulation (cost

[4] Consolidated into Docket No. E-22, Sub 562 by Commission Order Consolidating Dockets (May 2, 2019).

recovery of the Company's CCR costs, the recovery amortization period, and return during the amortization period);

- a rate of return on common equity of 9.75% and an overall rate of return on rate base of 7.20%;

- a capital structure for ratemaking purposes consisting of 52% equity and 48% long-term debt;

- an embedded cost of debt of 4.442%;

- agreement on numerous adjustments to the Company's cost of service;

- a $2.155 million decrease in DENC's annual base fuel revenues and a base fuel factor of 2.092¢/kWh, including regulatory fee;

- a decrement Rider A1, equal to (0.375¢/kWh) on a jurisdictional basis, calculated as the difference between the currently approved Rider B Experience Modification Factor (EMF) of 0.388¢/kWh and the proposed Rider B EMF in the Company's 2019 Fuel Case (Docket No. E-22, Sub 579) of 0.013¢/kWh;

- a Rider EDIT allowing for the recovery of $1,214,000 of federal EDIT, which includes the amortization of all unprotected federal EDIT totaling approximately $8.0 million partially offset by the refund of approximately $6.8 million associated with federal EDIT amortization attributable to the 22-month period of January 1, 2018, through October 31, 2019;

- allocation of the Company's cost of service based on the SWPA method, including adjustments to recognize the peak demand contributions of NUGs interconnected to the Company's distribution system and to remove the demand and energy requirements of three customers in DENC's Virginia jurisdiction for whom the obligation to provide generation service has ended or will end during 2019;

- inclusion of certain wet-to-dry conversion costs at the Chesterfield Power Station (Chesterfield) in the revenue requirement, subject to a similar dispute pending in the Company's Virginia jurisdiction; and

- agreement that the overall quality of electric service provided by DENC is good.

In support of the Public Staff Stipulation, Company witness McLeod testified that DENC, the Public Staff, and intervenors engaged in substantial discovery regarding the matters addressed in the Public Staff Stipulation. Witness McLeod further testified that the Public Staff Stipulation is the result of give-and-take negotiations in which each party made substantial compromises on individual issues in order to obtain a compromise from the other parties on other issues. He stated that the Stipulating Parties believe the results reached are fair to the Company and its customers. Witness McLeod also noted that the Public Staff Stipulation resolves all but one contested issue in the case between the Stipulating Parties without the necessity of contentious litigation. With respect to the contested issue not resolved by the Public Staff Stipulation, witness McLeod explained that $4.3 million of the CCR costs would be resolved outside of the Public Staff Stipulation as the Company would not support the "equitable sharing" methodology for these remaining CCR costs. Tr. vol. 4, 334-41.

Company witness Hevert also filed testimony in support of the Public Staff Stipulation. He testified that the 9.75% rate of return on common equity agreed to in the Public Staff Stipulation reflects negotiations among the Stipulating Parties and, taken as a whole with the rest of the Public Staff Stipulation, would be viewed by the financial community as constructive and equitable. Witness Hevert acknowledged that the 9.75% Stipulation rate of return on common equity falls below his recommended range of 10.00% to 11.00% but noted that the stipulated rate of return on common equity is a reasonable resolution of a complex and frequently contentious issue. Tr. vol. 4, 115-19.

Company witness Davis' testified in support of the Public Staff Stipulation's capital structure of 52.00% equity and 48.00% long-term debt. He stated that while differing from the recommendation in his direct testimony, the stipulated capital structure represents a reasonable compromise when considered within the context of the Public Staff Stipulation taken as a whole. Tr. vol. 4, 231-33.

Company witness Miller's testimony in support of the Public Staff Stipulation supported the cost of service issues agreed upon in the Public Staff Stipulation and provided updated schedules with a fully adjusted cost of service study showing the effects of all adjustments and rate changes to the North Carolina classes based on the Public Staff Stipulation. Tr. vol. 4, 538-42.

Finally, DENC witness Haynes' testimony in support of the Public Staff Stipulation explained the cost allocation, revenue apportionment, rate design, and cost of service studies agreed upon in the Public Staff Stipulation. Witness Haynes testified that the Public Staff Stipulation presents a just and reasonable approach to establishing the cost of service for the Company's North Carolina jurisdiction using the SWPA allocation methodology. He also explained that the SWPA methodology used the system load factor to weight the average component and the peak demand component, which was the same approach proposed in the Company's direct and rebuttal testimony, as well as the approach supported by Public Staff witness Floyd. Witness Haynes also explained that the Company still proposed to include decrement Rider A1 to mitigate the effect of the November 1, 2019, base non-fuel increase. Tr. vol. 4, 485-90.

Public Staff witnesses McLawhorn and Johnson filed joint testimony in support of the Public Staff Stipulation. They testified to the Public Staff's perception of several benefits provided by the Public Staff Stipulation, including a reduction in the base non-fuel revenue increase initially requested by DENC and the avoidance of protracted litigation between the Stipulating Parties. Similar to DENC witness McLeod, witnesses McLawhorn and Johnson stated that the CCR costs issue was not resolved in the Public Staff Stipulation and, therefore, the accounting and ratemaking adjustments cannot be finalized until the Commission makes a determination on that issue. Tr. vol. 6, 52.

Discussion and Conclusions

As the Public Staff Stipulation has not been adopted by all of the parties to this docket, the Commission's determination of whether to accept or reject the Public Staff Stipulation is governed by the standards set out by the North Carolina Supreme Court in *State ex rel. Utilities Commission v. Carolina Utility Customers Ass'n, Inc.*, 348 N.C. 452, 500 S.E.2d 693 (1998) (*CUCA I*), and *State ex rel. Utilities Commission v. Carolina Utility Customers Ass'n, Inc.*, 351 N.C. 223, 524 S.E.2d 10 (2000) (*CUCA II*). In *CUCA I*, the Supreme Court held:

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

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

However, as the Court made clear in *CUCA II*, the fact that fewer than all of the parties have adopted a settlement does not permit the Court to subject the Commission's Order adopting the provisions of a 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.

The Commission gives substantial weight to the testimony of DENC witness McLeod regarding the Stipulating Parties' efforts in negotiating the Public Staff Stipulation. Further, the Commission gives significant weight to the settlement testimony of Public Staff witnesses McLawhorn and Johnson, which in their discussion of the benefits that the Public Staff Stipulation will provide to customers and their testimony describing the compromise reflected in the Public Staff Stipulation's terms, indicate the Public Staff's commitment to fully represent the using and consuming public.

As a result, the Commission finds and concludes that the Public Staff Stipulation is the product of the give-and-take between the Stipulating Parties during their settlement negotiations in an effort to appropriately balance DENC's need for increased revenues and its customers' needs to receive safe, adequate, and reliable electric service at the lowest possible rates. In addition, the Commission finds and concludes that the Public Staff Stipulation was entered into by the Stipulating Parties after substantial discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute in this docket. As a result, the Public Staff Stipulation is material evidence to be given appropriate weight in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-9

The evidence supporting these findings of fact and conclusions is contained in the testimony of DENC witnesses Davis, Hevert, Miller, and Haynes; CIGFUR witnesses Wielgus and Thomas; and the entire record in this proceeding.

Summary of the Evidence

On September 23, 2019, DENC and CIGFUR (CIGFUR Stipulating Parties) filed the CIGFUR Stipulation resolving certain issues related to rate of return, cost allocation, rate design, and terms and conditions. In summary, the CIGFUR Stipulation provides:

- the Company's SWPA methodology calculated using the system load factor to weight the average component and (1 - system load factor) to weight the peak demand component is appropriate for use in allocating the Company's per books cost of service to the North Carolina jurisdiction and between customer classes in this case;

- DENC and CIGFUR agree to the two adjustments the Company made in the course of calculating the SWPA;

- in the next general rate case, the Company should file the results of a class cost of service study with production and transmission costs allocated on the basis of the Summer/Winter Coincident Peak method in addition to the SWPA used in this proceeding and consider such results for the sole purpose of apportionment of the change in revenue to the customer classes; and

- considering that no customers have taken service under the pilot Real Time Pricing (RTP) rates filed by the Company and approved by the Commission in Sub 532, the Company will work with CIGFUR to consider whether certain provisions within those rates should be modified. If there is mutual agreement between CIGFUR and DENC to such modifications, and CIGFUR indicates that at least one of its member customers is willing to take service under such rates,

> DENC agrees to re-file such rates with the Commission for approval with the modifications agreed upon within 60 days of such agreement.

At the hearing, Company witnesses Haynes and Miller stated their support for the CIGFUR Stipulation in the summaries of their testimonies. Witness Haynes stated that the CIGFUR Stipulation presents a just and reasonable approach to establishing the Company’s North Carolina jurisdictional cost of service and class cost of service for the allocation of production and transmission plant costs and related expenses based on the SWPA allocation methodology. He indicated that the Company believes the CIGFUR Stipulation represents a reasonable compromise of the allocation and rate design issues in this case, is fair to all parties, and should be approved by the Commission. Witness Miller stated that the CIGFUR Stipulation represents a reasonable compromise of the cost of service issues in this case, is fair to all parties, and should be approved by the Commission. Tr. vol. 4, 497, 545.

Discussion and Conclusions

As with the Public Staff Stipulation, because the CIGFUR Stipulation has not been adopted by all of the parties to this docket the Commission’s determination of whether to accept or reject the CIGFUR Stipulation is governed by the standards set out by the North Carolina Supreme Court in *CUCA I* and *CUCA II*.

The Commission gives significant weight to the testimony of DENC witnesses Haynes and Miller regarding the Company’s support for the CIGFUR Stipulation.

As a result, the Commission finds and concludes that the CIGFUR Stipulation is the product of the give-and-take between the CIGFUR Stipulating Parties during their settlement negotiations in an effort to appropriately balance DENC’s need for increased revenues and CIGFUR’s interest in advocating for its member customers. In addition, the Commission finds and concludes that the CIGFUR Stipulation was entered into by the CIGFUR Stipulating Parties after discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute in this docket. As a result, the CIGFUR Stipulation is material evidence to be given appropriate weight in this proceeding.

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

Capital Structure

The evidence supporting these findings of fact and conclusions is contained in the testimony and exhibits of Company witness Davis, Public Staff witness Woolridge, CIGFUR witness Phillips, and the Public Staff and CIGFUR Stipulations, as well as testimony and exhibits presented at the hearing of this matter.

In his prefiled direct testimony, DENC witness Davis proposed a capital structure consisting of 53.01% common equity and 46.99% long-term debt, DENC’s capital structure as of December 31, 2018. He discussed the Company's significant capital needs going forward, and explained how the Company plans to finance those capital needs, based on a balance of debt and common equity that DENC believes will support the Company's credit ratings going forward, and continue to enable the Company to access a number of markets, under a wide range of economic environments, on reasonable terms and conditions. Witness Davis stated that this market access is critical to fund the ongoing infrastructure capital expenditure programs that will be necessary to meet the Company's public service obligations in North Carolina and throughout its system. Tr. vol. 4, 204-09, 214-17.

In his supplemental testimony, witness Davis updated the Company's proposed capital structure to its actual structure as of June 30, 2019, which reflected a long-term debt component of 46.351% and an equity component of 53.649%. Based on the Company's proposed updated cost rates for long-term debt and common equity, witness Davis' proposed updated capital structure produced an updated overall weighted-average cost of capital of 7.826%. Tr. vol 4, 219-20.

Public Staff witness Woolridge testified that the Company's proposed capital structure included more common equity than the average of the proxy group he used in conducting his analysis. He stated that it is appropriate to use the common equity ratios of the parent holding companies and that the high debt ratio and low equity ratio of DEI is a credit negative for DENC as evaluated by Moody's. He noted, however, that because DENC is a regulated business, it is exposed to less risk and can carry relatively more debt in its capital structure than most unregulated companies, like DEI. Witness Woolridge further testified that DENC should take advantage of its lower business risk to employ cheaper debt capital at a level that will benefit its customers through lower revenue requirements and, as a result, recommended a capital structure of 50.00% common equity and 50.00% debt based on a 9.00% rate of return on common equity. Witness Woolridge also made an alternative capital structure recommendation of the Company's actual capital structure as of June 30, 2019, of 46.35% long-term debt and 53.65% common equity based on an 8.75% return on equity. Tr. vol. 6, 552-62.

CIGFUR witness Phillips testified that DENC's proposed capital structure includes more equity and less debt than other electric utilities and recommended a capital structure not to exceed 52.00% common equity. In support of his recommendation, witness Phillips analyzed the proxy groups that he claimed met the various jurisdictional regulatory capital structures of a comparable group of electric utility companies. He referenced groups that consisted of all electric utilities nationwide with equity ratios determined in the first half of 2019 and North Carolina gas and electric utilities that have had authorized rates of return on equity approved in recent years. Witness Phillips concluded that the Company's proposed capital structure was inconsistent with those authorized by the Commission in recent rate cases. Tr. vol 6, 412, 416, 429-31.

In his rebuttal testimony, witness Davis testified that witness Phillips' recommendation ignores the Company's actual capital structure as of June 30, 2019, as well as DENC's capital structure at year-end of each of the previous three years in favor of arbitrarily developed structures. Witness Davis stated that it is important that the Company's actual capital structure be considered in determining the appropriate capital structure for purposes of this rate case because imputing the structure of other peer utilities in different jurisdictions can lead to erroneous conclusions. He also explained that the Company's financing plan is structured to maintain the Company's current credit ratings, which provide the greatest benefit to customers in the long-term. Witness Davis stated that an arbitrarily derived capital structure could be viewed negatively by the Company's credit agencies. Finally, witness Davis explained that using the Company's actual capital structure helps to support the significant capital spending program the Company has and continues to undertake to enhance and improve DENC's generation and transmission infrastructure. Tr. vol. 6, 221-29.

Under Section III.A of the Public Staff Stipulation, the Stipulating Parties proposed a capital structure of 52% common equity and 48% long-term debt. In their stipulation testimony, Company witness Davis and Public Staff witnesses Johnson and McLawhorn testified that the capital structure reflected in the Public Staff Stipulation represents a compromise by both parties in an effort to reach agreement and is in the public interest. Witness Davis testified that the capital structure represented in the Stipulation provides an equity ratio that is 165 basis points lower than the Company's request of 53.649%, 200 basis points higher than the Public Staff's initial recommendation presented in witness Woolridge's testimony, and 25 basis points higher than the equity ratio authorized in the 2016 Rate Case. Witness Davis stated that he, like the Public Staff witnesses, believes the end result of the settlement is fair and reasonable with respect to both ratepayers and shareholders, and that such a ratio will allow the Company to continue providing safe and reliable service to its customers. Tr. vol. 6, 51-52, vol. 4, 231-33.

In the CIGFUR Stipulation, CIGFUR and DENC stipulated that it was appropriate to use a capital structure consisting of 52% equity and 48% long-term debt.

In evaluating the evidence on capital structure in this proceeding, the Commission first notes that the equity/debt ratios reflected in the Stipulation of 52.00% equity and 48.00% long-term debt are consistent with and well within the prior experience of the Commission.[5] These are not determinative factors from the Commission's perspective, but they do provide some context supporting the reasonableness of the stipulated capital structure.

Based upon its own review and independent analysis of the evidence, the Commission concludes that a capital structure of 52.00% equity and 48.00% long-term debt, as is reflected in the Public Staff Stipulation, is just and reasonable and appropriate for use in this proceeding on several grounds.

[5] *See* DENC Sub 532 Order (51.75% common equity and 48.25% debt); PSNC Sub 565 Order (52.0% common equity, 44.62% long-term debt, 3.38% short-term debt); PNG Sub 743 Order (52.00% equity, 47.15% long-term debt, 0.85% short-term debt); DEC Sub 1146 Order (52% common equity and 48% long-term debt); DEP Sub 1142 Order (52% common equity and 48% long-term debt).

First, this capital structure is very close, i.e., 25 basis points, to the capital structure authorized for DENC in its last rate case. Second, this capital structure was accepted by CIGFUR in the CIGFUR Stipulation. Third, while the Commission recognizes that Public Staff witness Woolridge recommended a 50% common equity and 50% debt capital structure based on a 9.00% rate of return on equity as his primary recommendation, he also proposed use of the actual capital structure as of December 31, 2018, of 46.351% long-term debt and 53.649% common equity based on an 8.75% return on equity. Fourth, Section X of the Public Staff Stipulation provides:

> [T]his Stipulation is in the public interest because it reasonably balances customer interests in mitigating rate impacts with investor interests in providing for reasonable recovery of investments, thereby providing the necessary level of revenue requirement to allow the Company to maintain its financial strength and credit quality and continue to provide high quality electric utility service to its customers.

Fifth, Section IV of the CIGFUR Stipulation contains this same language. Sixth, the Commission gives substantial weight to Company witness Davis' testimony regarding the Company's effort to find the appropriate balance between equity and debt financing. As witness Davis noted, witness Phillips relies primarily on the averages of his respective proxy groups without providing any further rationale in support of his recommended capitalization ratios. Seventh, the Commission places substantial weight as well on witness McLawhorn's and witness Johnson's conclusion that the end result of the settlement is fair and reasonable with respect to both ratepayers and shareholders, and that customers will benefit from lower rates as a result of a negotiated settlement that, if approved, will reduce the Company's proposed rate increase by at least $13 million. Eighth, the Commission also gives weight to the Public Staff Stipulation and the benefits that it provides to DENC's customers, which the Commission is obliged to consider as an independent piece of evidence under *CUCA I* and *CUCA II*. Each party to the Public Staff Stipulation gained some benefits that it deemed important and gave some concessions for those benefits. Based on the Application and pre-filed testimony, it is apparent that the Public Staff Stipulation ties the 52/48 capital structure to substantial concessions the Company made to reduce its revenue requirement.

Accordingly, based on the matters set forth above, and in the exercise of its independent judgment, the Commission finds that the weight of the evidence in this proceeding favors using the stipulated capital structure and that such capital structure is just, reasonable, and appropriate for use in setting rates in this docket.

Cost of Debt

The evidence supporting this finding of fact and conclusions is contained in the testimony and exhibits of Company witness Davis and Public Staff witness Woolridge, the Public Staff and CIGFUR Stipulations, and the entire record of this proceeding.

In its Application and supporting testimony, the Company proposed a long-term debt cost of 4.45% at the end of the test year. In his supplemental testimony, Company witness Davis updated the debt cost to 4.442% as of June 30, 2019. The Public Staff and CIGFUR Stipulations accept the 4.442% cost of debt proposed by the Company in witness Davis' supplemental testimony. No party contested the cost of debt proposed by the Company or agreed upon in the Public Staff and CIGFUR Stipulations.

The Commission, therefore, finds and concludes that the use of a debt cost of 4.442% is just and reasonable to all parties in light of all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-16

The evidence for these findings of fact and conclusions is contained in the Application; the direct testimony and exhibits of witnesses Hevert, Woolridge, and Phillips; the Public Staff and CIGFUR Stipulations; the testimony of public witnesses; the rebuttal testimony of witness Hevert; the settlement testimony of witnesses Hevert, McLawhorn, and Johnson; and the hearing testimony of witness Hevert.

The Public Staff and CIGFUR Stipulations both state that an allowed rate of return on common equity of 9.75% is reasonable for use in this proceeding, a decrease from the 9.9% level authorized by the Commission in the Company's last rate case. No other party presented evidence on the appropriate rate of return on common equity. The Commission's consideration of the evidence and decision on this issue is set out below and is organized into three sections. The first is a summary of the record evidence on rate of return on common equity. The second is a summary of the law applicable to the Commission's decision on rate of return on common equity. The third is an application of the law to the evidence and a discussion and explanation of the Commission's ultimate decision on rate of return on common equity.

Summary of Record Evidence on Return on Equity

In its Application, the Company requested approval for its rates to be set using an overall rate of return of 7.79% and a rate of return on equity of 10.75%. This request was based upon and supported by the direct testimony of DENC witness Hevert. These rates of return compare to an overall return of 7.367% and rate of return on common equity of 9.90% underlying DENC's current rates. DENC witness Mitchell also filed testimony supporting the approval of the rate of return on common equity recommended by witness Hevert. Witnesses for the Public Staff and CIGFUR also filed direct testimony on the appropriate rate of return on equity. This evidence was followed by the Public Staff and CIGFUR Stipulations, rebuttal testimony filed by witness Hevert, settlement testimony filed by DENC witness Hevert and Public Staff witnesses McLawhorn and Johnson, and finally testimony of witness Hevert at the hearing of this matter. In addition to this expert testimony, the Commission received the testimony of a number of public witnesses on DENC's proposed rate increase as well as numerous statements of consumer position. All of this evidence is summarized below.

Direct Testimony of Mark Mitchell (DENC)

DENC witness Mitchell testified that the Company was facing significant capital investment needs. He stated that in order to attract the capital to meet these substantial future needs, the Company must achieve an adequate authorized rate of return on common equity in this proceeding, and that the 10.75% rate of return on common equity proposed by DENC would allow the Company to attract capital on reasonable terms in the capital markets. He explained that the ability to attract capital on favorable terms is important to DENC's ability to maintain its current credit ratings and, ultimately, minimize the cost of capital for customers, and that an adequate return also ensures DENC's ability to commit capital to future construction projects to provide safe, reliable, and cost-effective electric service to North Carolina customers without eroding the Company's shareholders' interests. Tr. vol. 4, 168, 177-82.

Direct Testimony of Robert B. Hevert (DENC)

Witness Hevert, DENC's primary cost of equity witness, filed direct testimony and exhibits in support of DENC's request for a 10.75% rate of return on common equity. He explained that the cost of equity is the return that investors require to make an equity investment in a company, that it should reflect the return that investors require in light of the company's risks and the returns available on comparable investments, and that it differs from the cost of debt because it is neither directly observable nor a contractual obligation. In his direct testimony and exhibits, witness Hevert discussed the specific analyses he conducted in support of DENC's rate filing and provided a detailed description of the results of these analyses and resulting cost of equity recommendations. He applied the Constant Growth Discounted Cash Flow (DCF) model, the Capital Asset Pricing Model (CAPM), the Empirical Capital Asset Pricing Model (ECAPM), the Bond Yield Plus Risk Premium approach, and the Expected Earnings Analysis to develop his rate of return on equity recommendation. He stated that the Commission's decision should result in providing DENC with the opportunity to earn a rate of return on common equity that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks. He discussed the need to select a group of proxy companies to determine the cost of equity, and how he selected the proxy group for this case. Witness Hevert also noted that the regulatory conditions approved by the Commission in the merger of DENC's parent company, DEI, and SCANA Corporation were designed to ensure that the Company has "sufficient access to equity and debt capital at a reasonable cost to adequately fund and maintain their current and future capital needs and otherwise meet their service obligations to their customers." Tr. vol. 4, 32-33.

According to witness Hevert, the results of his Constant Growth DCF analysis produced a rate of return on equity range of 8.34% to 10.38%. The results of witness Hevert's CAPM analysis showed a range of 8.25% to 11.34% in market risk premiums. The results of his ECAPM analysis showed a range of 9.61% to 12.76% in rate of returns on equity. The results of his Bond Yield Plus Risk Premium analysis indicated a rate of return on common equity range from 9.93% to 10.17%. The results of his Expected

Earnings Analysis showed an average rate of return on common equity of 10.38% and a median rate of return on equity of 10.52%. Based on his analyses, witness Hevert concluded that a rate of return on common equity in the range of 10.00% to 11.00% represents the rate of return on common equity required by equity investors for investment in integrated electric utilities in today's capital markets. Within that range, he recommended a rate of return on common equity for DENC of 10.75% in both his direct and rebuttal testimony. Tr. vol. 4, 45-56.

Witness Hevert explained that his rate of return on common equity recommendation also took into consideration several additional factors, including (1) DENC's need to fund its substantial planned capital investment program, (2) the regulatory environment in which the Company operates, and (3) flotation costs. With regard to the regulatory environment, he noted that North Carolina is generally considered to be a constructive regulatory jurisdiction, and that authorized rates of return on common equity tend to be correlated with the degree of regulatory supportiveness (utilities in jurisdictions considered to be more supportive tend to be authorized somewhat higher returns). He did not, however, make any specific adjustment to his rate of return on common equity estimates for the effect of these factors. Tr. vol. 4, 56-67.

Witness Hevert also addressed the capital market environment and testified that it is important to assess the reasonableness of any financial model's results in the context of observable market data. In particular, he discussed the fact that investors see a probability of increasing interest rates based on near-term forecasts of the 30-year Treasury yield. Tr. vol. 4, 77-81.

Witness Hevert also considered the economic conditions in North Carolina in arriving at his rate of return on common equity recommendation. He noted that the rate of unemployment has fallen substantially in North Carolina and in the U.S. generally since late 2009 and early 2010, with December 2018 rates of 3.70% in the State. He noted that since the Company's last general rate filing in March 2016, unemployment in the counties served by DENC has fallen by 1.40%. Witness Hevert also noted that since the second quarter of 2013, the State has generally matched the national rate for real GDP, but that since 2009, median household income in North Carolina has grown at a somewhat slower annual rate than the national median income annual rate than the national median income. Total personal income, disposable income, personal consumption, and wages and salaries were generally on an increasing trend. Finally, he noted that since 2018, residential electricity costs in North Carolina remain approximately 13.00% below the national average. Based on all of these factors, witness Hevert opined that North Carolina and the counties contained within DENC's service area have experienced steady economic improvement since the Company's last rate case and that improvement is projected to continue. In his opinion, DENC's proposed rate of return on common equity is fair and reasonable to DENC, its shareholders and its customers, in light of the impact of changing economic conditions on DENC's customers. Tr. vol. 4, 67-77.

Direct Testimony of J. Randall Woolridge (Public Staff)

Public Staff witness Woolridge performed DCF and CAPM analyses for both his and witness Hevert's proxy groups of electric utilities. Witness Woolridge developed his DCF growth rate after reviewing 13 growth rate measures including historic and projected growth rate measures and evaluating growth in dividends, book value, earnings per share (EPS), and growth rate forecasts from Yahoo, Reuters, and Zack's. Witness Woolridge testified that it is well known that long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. Public Staff witness Woolridge determined a DCF equity cost rate of 8.55% for his proxy group, and 8.95% for the witness Hevert proxy group. Tr. vol. 6, 534-37.

In witness Woolridge's CAPM analysis, he used for the risk free interest rate the top end of the range of yields on 30-year U.S. Treasury bonds over the 2013-2019 time period, 4.00%. He used the Value Line Investment Survey betas of 0.60 for his proxy group and 0.58 for witness Hevert's proxy group. Witness Woolridge's market risk premium was 5.50%, based in part on the June 2019 CFO survey conducted by CFO Magazine and Duke University, which included approximately 200 responses, in which the expected market risk premium was 4.05%. He testified that thus, his 5.50% value is a conservatively high estimate of the market risk premium. Witness. Woolridge also testified that Duff & Phelps, a well-known valuation and corporate finance advisor that publishes extensively on cost of capital, recommended on December 31, 2018, using a 5.5% market risk premium, for the U.S. Witness Woolridge's CAPM equity cost rate was 7.30% for his proxy group and 7.20% for witness Hevert's proxy group. Tr. vol. 6, 591-604.

Witness Woolridge concluded that the appropriate equity cost rate for companies in his and witness Hevert's proxy groups is in the 7.20% to 8.95% range. He gave primary weight to his DCF results based on his belief that risk premium studies, including the CAPM, are a less reliable indicator of equity cost rates for public utilities. Witness Woolridge also indicated that he found the DCF model to provide the best measure of equity cost rates considering the investment valuation process and the relative stability of the utility business. Tr. vol. 6, 531, 604-05.

While noting that his equity cost rate studies indicated a rate of return on common equity between 7.20% and 8.95%, witness Woolridge took into account the fact that his range was below the authorized rates of return on common equity for electric utilities nationally and made a primary recommendation of a 9.00% rate of return on equity, assuming a 50.00% common equity ratio. Witness Woolridge also provided an alternative recommendation of an 8.75% rate of return on common equity based on the Company's originally recommended equity ratio of 53.649%. Tr. vol. 6, 532-33.

Witness Woolridge did not perform an ECAPM analysis and testified that the ECAPM is an ad hoc version of the CAPM and has not been theoretically or empirically validated in refereed journals. He also took issue with witness Hevert's Bond Yield Plus Risk Premium analysis and argued that it is inflated, gauges commission behavior rather than investor behavior, and overstates the actual rate of return on common equity. Tr. vol. 6, 612-13, 640-44.

Witness Woolridge also expressed concerns with witness Hevert's Expected Earnings analysis and argued that the approach is inappropriate for several reasons: (1) it is accounting based and does not measure market based investor return requirements; (2) book equity does not change with investor return requirements as do market prices; (3) there is a negative relationship between the Return on Common Equity and Common Equity ratios; (4) the approach is circular; and (5) the data partially reflect earnings of non-regulated operations. Tr. vol. 6, 613, 644-48.

Witness Woolridge also testified as to current capital market conditions as of the date of his testimony in August 2019. He stated that although the Federal Reserve increased the Federal Funds rate between 2015 and 2018, interest rates and capital costs remained at low levels. Witness Woolridge also pointed out that the 30-year Treasury yields are at historically low levels and are accompanied by slow economic growth and low inflation. Tr. vol. 6, 548, 591, 610.

Witness Woolridge responded to witness Hevert's assessment of the economic conditions in North Carolina. He generally agreed with witness Hevert's review of several measures of economic conditions, including the rate of unemployment, real GDP growth, median household income, residential electricity rates, and broad measures of income and consumption, as well as witness Hevert's general conclusion that economic conditions in North Carolina have improved since the Company's last rate case. Witness Woolridge argued, however, that although economic conditions generally have improved, other conditions such as the higher unemployment rate in the DENC service territory as opposed to the whole state, and the median household income in North Carolina that is lower than the national norm, as well as the over 100 basis point difference in DENC's requested rate of return on common equity and the average authorized rates of return on equity for electric utilities in 2018-2019, do not support the Company's proposed rate of return. Tr. vol. 6, 652-55.

Direct Testimony of Nicholas Phillips, Jr. (CIGFUR)

CIGFUR witness Phillips did not perform cost of capital analyses. In his testimony witness Phillips found the Company's proposed rate of return on equity to be excessive based on his review of authorized rates of return on common equity for the first half of 2019, which averaged 9.57%, as reported by RRA. Witness Phillips recommended that the Commission authorize a rate of return on common equity that does not exceed the national average of 9.57%. Tr. vol. 6, 427-31.

Rebuttal Testimony of Robert B. Hevert (DENC)

In his rebuttal testimony, Company witness Hevert responded to the arguments raised by CIGFUR witness Phillips. Witness Hevert explained that he analyzed the authorized rate of return on common equity for vertically integrated electric utilities based on the jurisdiction's ranking by RRA, which provides an assessment of the extent to which regulatory jurisdictions are constructive from investors' perspectives. Witness Hevert stated that according to RRA, less constructive environments are associated with higher levels of risk, but North Carolina currently is ranked "Average/1," which falls approximately in the top-third of the 53 jurisdictions ranked by RRA. Witness Hevert testified that authorized rates of return on common equity for vertically integrated electric utilities in jurisdictions rated in the top third of all jurisdictions, like North Carolina, range from 9.37% to 10.55%, with an average of 9.93%, and a median of 9.95%. Finally, witness Hevert pointed to Company Rebuttal Exhibit RBH-16, which shows that the mean and median authorized rates of return on common equity for 2019, updated through August 16, 2019, are 9.61% and 9.73%, respectively. Tr. vol. 4, 107-12.

Public Staff and CIGFUR Stipulations

In both the Public Staff and the CIGFUR Stipulations, DENC and the Public Staff, and DENC and CIGFUR agreed that the appropriate overall rate of return and rate of return on common equity for use in this proceeding were 7.20% and 9.75%, respectively. These agreements represent substantial movement by the parties from the positions on overall return and return on common equity articulated in testimony. This stipulated overall return of 7.20% and return on common equity of 9.75% was supported by settlement testimony filed by Company witness Hevert. The overall reasonableness of the stipulated rates of return was also addressed by Public Staff witnesses McLawhorn and Johnson in their settlement testimony.

Settlement Testimony of Robert B. Hevert (DENC)

In his testimony supporting the Stipulations, witness Hevert noted that although the 9.75% stipulated rate of return on common equity is somewhat below the lower bound of his recommended range, he recognized that the Stipulations reflect negotiation on many issues between the parties. Witness Hevert stated that the terms of the Stipulations, when taken as a whole, would be regarded favorably by the financial community. He noted that the median rate of return on common equity authorized in 2019 at the time of his testimony was 9.73%, only two basis points from the stipulated rate of return on common equity. Witness Hevert testified that the stipulated rate of return on common equity fell below his Risk Premium model results, it fell in the 69th percentile of the mean and median of his DCF results, the 32nd percentile of his CAPM and ECAPM results, and the 40th percentile of his Expected Earnings analysis. Thus, witness Hevert concluded that the stipulated rate of return on equity was supported by returns in other jurisdictions and fell within the range of his model results, though at the lower end. Tr. vol. 4, 116-19.

Hearing Testimony of Robert B. Hevert (DENC)

Under cross-examination by the AGO, witness Hevert defended the use of projected treasury yields in his CAPM analysis by pointing out that there was only about a 21-basis point difference between the current and projected treasury yields, which was not a material difference. He noted that the CAPM results based on the current yield also support his recommendation. Witness Hevert also pointed out that using projected yields gave an important perspective, especially in light of the fact that in the recent market, the 30-year Treasury yield fell 71 basis points in 34 trading days. He further pointed out that in the Sub 1142 Order in DEP's 2017 rate case and a recent Virginia case the commissions found his DCF analysis to produce unreasonably low rate of return on equity results, even using only earnings estimates. Witness Hevert did not dispute that of the 32 data points he considered in determining his range and recommended rate of return on equity, 24 were lower than his recommended rate of return on common equity. Nonetheless, witness Hevert noted that a mean of these results would not necessarily provide an appropriate estimate of DENC's cost of equity, as various qualitative factors should also be considered, such as capital expenditure plans and the regulatory environment. Tr. vol. 4, 143-47.

Public Witness Testimony/Statements of Consumer Position

In addition to the direct prefiled testimony of the expert witnesses for the parties, a number of public witnesses also gave testimony suggesting that DENC customers would experience difficulty paying the increased rates requested in the Application and opposing the rate increases proposed by DENC. The Commission also received numerous statements of consumer position with regard to this docket, many of which expressed concern about DENC's proposed rate increase.

Law Governing the Commission's Decision on Return on Equity

Rate of return on common equity 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 stipulations between DENC and the Public Staff and DENC and CIGFUR have been reached. In the absence of a settlement agreed to by all the parties, the law of North Carolina requires the Commission to exercise its independent judgment and arrive at its own independent conclusion as to the proper rate of return on common equity. *See, e.g., CUCA I,* 348 N.C. at 466, 500 S.E.2d at 707. In order to reach an appropriate independent conclusion regarding the rate of return on common equity, the Commission must evaluate the available evidence, particularly that presented by conflicting expert witnesses. *State ex rel. Utils. Comm'n v. Cooper*, 366 N.C. 484, 491-93, 739 S.E.2d 541, 546-47 (2013) (*Cooper I*). In this case, the expert witness evidence relating to the Company's cost of equity capital was presented by Company witness Hevert, Public Staff witness Woolridge, and CIGFUR witness Phillips. No return on equity evidence was presented by any other party.

The baseline for establishment of an appropriate rate of return on common equity is the constitutional constraints established by the decisions of the United States Supreme Court in *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n* *of W. Va.,* 262 U.S. 679 (1923) (*Bluefield*), and *Fed. Power Comm'n v. Hope Nat. Gas Co.,* 320 U.S. 591 (1944) (*Hope*) which establish that:

> 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 rate of return on common equity], 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.

DEC Sub 1146 Order at 50; *see also State ex rel. Utils. Comm'n v. Gen. Tel. Co. of the Se.*, 281 N.C. 318, 370, 189 S.E.2d 705, 738 (1972) (*General Telephone*). As the North Carolina Supreme Court held in *General Telephone*, these factors constitute "the test of a fair rate of return declared" in *Bluefield* and *Hope*. *Id.*

It is also important for the Commission to keep in mind that the rate of return on equity is, in fact, a cost. The return that equity investors require represents the cost to the utility of equity capital. In his dissenting opinion in *Missouri ex rel. Southwestern Bell Telephone Co. v. Missouri Public Service Commission*, 262 U.S. 276 (1923), Justice Brandeis remarked upon the lack of any functional distinction between the rate of return on equity (which he referred to as a "capital charge") and other items ordinarily viewed as business costs, including operating expenses, depreciation, and taxes:

> Each is a part of the current cost of supplying the service; and each should be met from current income. When the capital charges are for interest on the floating debt paid at the current rate, this is readily seen. But it is no less true of a legal obligation to pay interest on long-term bonds . . . *and it is true also 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*, "[f]rom 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. at 591, 603.

Leading academic commentators also define rate of return on equity as the cost of equity capital. Professor Charles Phillips, for example, states that "the term 'cost of capital' may be defined as the annual percentage that a utility must receive to maintain its credit, to pay a return to the owners of the enterprise, and to ensure the attraction of capital in amounts adequate to meet future needs." Phillips, Charles F, Jr., *The*

Regulation of Public Utilities 388 (Public Utilities Reports, Inc. 1993). Professor Roger Morin approaches the matter from the economist's viewpoint:

> While utilities enjoy varying degrees of monopoly in the sale of public utility services, they must compete with everyone else in the free open market for the input factors of production, whether it be labor, materials, machines, or capital. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices which are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require, for example, the interest on capital debt, or the expected return on equity.
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> . . .
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> [T]he cost of capital to the utility is synonymous with the investor's return, and the cost of capital is the earnings which must be generated by the investment of that capital in order to pay its price, that is, in order to meet the investor's required rate of return.

Morin, Roger A., *Utilities' Cost of Capital* 19-21 (Public Utilities Reports, Inc. 1984). 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.

In addition, the Commission is and must always be mindful of the North Carolina Supreme Court's command that the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions. *State ex rel. Utils. Comm'n v. Pub. Staff-N. Carolina Utils. Comm'n*, 323 N.C. 481, 490, 374 S.E.2d 361, 370 (1988) (*Public Staff*). Further, and echoing the discussion above concerning the fact that rate of return on equity represents the cost of equity capital, the Commission must execute the Supreme Court's command "irrespective of economic conditions in which ratepayers find themselves." Order Granting General Rate Increase, *Application of Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., for Adjustment of Rates and Charges Applicable to Electric Utility Service in North* Carolina, No. E-2, Sub 1023, at 37 (N.C.U.C. May 30, 2013), *aff'd*, *State ex rel. Utils. Comm'n v. Cooper*, 367 N.C. 444, 761 S.E.2d 640 (2014) (2013 DEP Rate Case Order). 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 other times, which would seem to be a logical but misguided corollary to the position the Attorney General advocates on this issue.

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

The Commission further noted in the 2013 DEP Rate Case Order that while there is no specific and discrete numerical basis for quantifying the impact of economic conditions on customers, the impact on customers of changing economic conditions is embedded in the rate of return on equity expert witnesses' analyses. The Commission noted this in the 2013 DEP Rate Case Order:

> This impact is essentially inherent in the ranges presented by the return on equity expert witnesses whose testimony plainly recognizes economic conditions — through the use of economic models — as a factor to be considered in setting rates of return.

2013 DEP Rate Case Order at 38.

Finally, under long-standing decisions of the North Carolina Supreme Court, the Commission's subjective judgment is a necessary part of determining the authorized rate of return on common equity. *Public Staff*, 323 N.C. at 490, 374 S.E.2d at 369. As the Commission has previously noted:

> Indeed, of all the components of a utility's cost of service that must be determined in the ratemaking process the appropriate [rate of return on common equity] is the one requiring the greatest degree of subjective judgment by the Commission. Setting [a rate of return on common equity] for regulatory purposes is not simply a mathematical exercise, despite the quantitative models used by the expert witnesses. As explained in one prominent treatise,
>
> > Throughout all of its decisions, the [United States] Supreme Court has formulated no specific rules for

> determining a fair rate of return, but it has enumerated a number of guidelines. The Court has made it clear that confiscation of property must be avoided, that no one rate can be considered fair at all times and that regulation does not guarantee a fair return. The Court also has consistently stated that a necessary prerequisite for profitable operations is efficient and economical management. Beyond this is a list of several factors the commissions are supposed to consider in making their decisions, but no weights have been assigned.
>
> The relevant economic criteria enunciated by the Court are three: financial integrity, capital attraction and comparable earnings. Stated another way, the rate of return allowed a public utility should be high enough: (1) to maintain the financial integrity of the enterprise, (2) to enable the utility to attract the new capital it needs to serve the public, and (3) to provide a return on common equity that is commensurate with returns on investments in other enterprises of corresponding risk. These three economic criteria are interrelated and have been used widely for many years by regulatory commissions throughout the country in determining the rate of return allowed public utilities.
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> In reality, the concept of a fair rate of return represents a "zone of reasonableness." As explained by the Pennsylvania commission:
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>> There is a range of reasonableness within which earnings may properly fluctuate and still be deemed just and reasonable and not excessive or extortionate. It is bounded at one level by investor interest against confiscation and the need for averting any threat to the security for the capital embarked upon the enterprise. At the other level it is bounded by consumer interest against excessive and unreasonable charges for service.
>
> As long as the allowed return falls within this zone, therefore, it is just and reasonable. . . . It is the task of the commissions to translate these generalizations into quantitative terms.

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

2013 DEP Rate Case Order at 35-36 (additions and omissions after the first quoted paragraph in original).

Moreover, the North Carolina Supreme Court has interpreted N.C.G.S. § 62-133 as requiring the Commission to make findings regarding the impact of changing economic conditions on customers when determining the proper rate of return on equity for a public utility. *Cooper I*, 366 N.C. at 495, 739 S.E.2d at 548. The Commission must exercise its subjective judgment so as to balance two competing rate of return on equity-related factors—the economic conditions facing the Company's customers and the Company's need to attract equity financing in order to continue providing safe and reliable service. 2013 DEP Rate Case Order at 35-36.

In addition to adhering to the broad controlling legal principles on the allowed rate of return discussed above, the Commission must adhere to the multi-element formula set forth in N.C.G.S. § 62-133 when it sets rates. The rate of return on cost of property element of the formula in N.C.G.S. § 62-133(b)(4) is a significant, but not an independent element. Each element of the formula must be analyzed to determine the utility's cost of service and revenue requirement. The Commission must make many subjective decisions with respect to each element in the formula in establishing the rates it approves in a general rate case. The Commission must approve accounting and pro forma adjustments to comply with N.C.G.S. § 62-133(b)(3) and must approve depreciation rates pursuant to N.C.G.S. § 62-133(b)(1). The subjective decisions the Commission makes as to each of these elements have multiple and varied impacts on the decisions it makes on other rate-affecting elements, such as the decision it must make on the rate of return on common equity.

Pursuant to N.C.G.S. § 62-133(c), rates in North Carolina are set based on a modified historic test period. A component of cost of service equally important as the return on investment component is test year revenues. N.C.G.S. § 62-133(b)(3). 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. Economic conditions existing during the test year, at the time of the public hearings, and at the date of this Order will affect not only the ability of DENC's customers to pay electric rates, but also the ability of DENC to earn the authorized rate of return during the period rates will be in effect. Thus, in accordance with the above-discussed applicable law, the Commission's duty under N.C.G.S. § 62-133 is to set rates as low as reasonably possible without impairing the Company's ability to attract investors to raise the capital needed to provide reliable electric service and recover its cost of providing service.

In fixing rates, the Commission is also cognizant that when a utility's costs and expenses grow at a faster pace than revenues during the period when rates will be in effect, it 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, earned return is less than the authorized return, an occurrence commonly referred to as regulatory lag. In setting the rate of return, just as the Commission is constrained to address the impact of 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 is constrained to address the effect of regulatory lag on the Company by establishing a higher rate of return on equity. Instead, the Commission sets the rate of return considering both of these negative impacts in its ultimate decision fixing a utility's rates.

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

Discussion and Application of Law to the Facts

The Commission has examined the Company's Application and supporting testimony and exhibits and Form E-1 filings seeking to justify its requested increase. DENC's updated request prior to entering into the stipulations was a retail revenue increase of $24.2 million in annual revenues. The Public Staff, who in this docket represents all users and consumers of the Company's electric service, and DENC entered into a stipulation that resulted in reducing the retail revenue increase sought by the Company. CIGFUR and DENC entered into a separate stipulation that provided for the same reduction in the revenue increase, as well as a 9.75% rate of return on common equity. As with all settlement agreements, each party to the stipulations gained some benefits that it deemed important and gave some concessions for those benefits. Based on DENC's Application, it is apparent that the stipulations tie the 9.75% rate of return on common equity to substantial agreed upon concessions made by DENC. As noted above, since the AGO and Nucor, parties in this docket, did not agree to the settlements, the Commission is required to examine the stipulations and exercise its independent judgment to arrive at its own independent conclusion as to the proper rate of return on common equity.

The starting point for an examination of what constitutes a reasonable rate of return on common equity begins with the various economic and financial analyses provided by the parties' expert witnesses. In this proceeding, those analyses were provided in the testimonies of three different witnesses: witness Hevert for DENC; witness Woolridge for the Public Staff; and witness Phillips for CIGFUR. These testimonies, as summarized above, provide a relatively broad range of methods, inputs, and recommendations regarding the proper rate of return on common equity determination for DENC. For example, witness Hevert relied in his direct testimony on four different analyses to arrive at his rate of return on common equity recommendation. These analyses were a Constant Growth DCF Analysis, a Capital Asset Pricing Model analysis, an Empirical Capital Asset

Pricing Model, a Bond Yield Plus Risk Premium analysis, and an Expected Earnings analysis. By way of comparison, Public Staff witness Woolridge relied upon a DCF analysis and a Capital Asset Pricing Model analysis in reaching his conclusions; however, the inputs utilized by witness Woolridge in his analyses are different from those utilized by witness Hevert. Witness Phillips looked at the average allowed rates of return on common equity for both vertically integrated and distribution-only electric utilities for the first and second quarters of 2019 of 9.57% and recommended that average as a cap to the allowed rate of return on common equity.

These varying analyses, as is typical, produced varying results. Witness Hevert's analyses prompted him to propose a rate of return on common equity range of 10.00% to 11.00% with a specific rate of return on common equity recommendation of 10.75%. Witness Woolridge's analyses resulted in a recommended rate of return on common equity range of 7.20% to 8.95% with a primary recommendation of a 9.00% rate of return on common equity with a 50.00% common equity capital structure and a secondary recommendation of an 8.75% rate of return on common equity if DENC's actual capital structure of 46.351% long-term debt and 53.649% common equity, as proposed in the supplemental testimony of Company witness Davis, was approved. Finally, as noted above, witness Phillips recommended a cap on rate of return on common equity of 9.57%.

The Commission finds the cost of equity analyses helpful in reaching its conclusion on an appropriate rate of return on common equity for DENC, but notes that the ranges of the various analyses span a range from 7.20% to 12.76% and the specific rate of return on common equity recommendations of the witnesses span a range from 8.75% on the low end to 10.75% on the high end.

The Commission finds that the DCF, CAPM, ECAPM, and Bond Yield Plus Risk Premium analyses of DENC witness Hevert, and the stipulations are credible, probative, and entitled to substantial weight.

DENC witness Hevert in his direct testimony provided his constant growth DCF analyses, as shown on Exhibit RBH-1, pages 1, 2, and 3: 30-day dividend yield mean 9.24%, median 9.18%; 90-day dividend yield mean 9.31%, median 9.25%; and 180-day dividend yield mean 9.39%, median 9.38%. Although the Commission, as stated in previous Commission general rate case orders, does not approve of witness Hevert's sole use of analysts' predicted earnings per share to determine the DCF growth rate, the Commission finds witness Hevert's constant growth DCF analyses mean and median rate of return on common equity results credible, probative, and entitled to substantial weight.

Witness Hevert's CAPM analysis for his Proxy Group Average Value Line Beta Coefficient, as shown on Exhibit RBH-4, page 1, includes current 30-year treasury rates to calculate the risk free rate of 3.04%, producing what witness Hevert described as a Value Line Market DCF Derived rate of return on equity of 9.78%. Witness Hevert's ECAPM analysis for his Proxy Group Average Bloomberg Beta Coefficient, as shown on Exhibit RBH-4, page 1, produces what witness Hevert described as a Bloomberg Market DCF Derived rate of return on common equity of 9.61%. The Commission approves of the use of current risk-free rates rather than predicted near-term or long-term rates. The Commission finds the above-described CAPM and ECAPM analyses credible, probative, and entitled to substantial weight.

DENC witness Hevert's Bond Yield Plus Risk Premium, as shown on Exhibit RBH-5, using the current 30-year Treasury yield of 3.04% and applying it to the approved rates of return on common equity in 1,581 electric utility rate proceedings between January 1980 and February 28, 2019, results in a rate of return on common equity of 9.93%. As previously stated, the Commission approves the use of current interest rates, rather than projected near-term or long-term interest rates. The Commission finds witness Hevert's updated Bond Yield Plus Risk Premium analysis using the current 30-year Treasury yield to be credible, probative, and entitled to substantial weight.

The Commission has carefully evaluated the DCF analysis recommendation of witness Woolridge. As shown on witness Hevert's settlement testimony Exhibit RBH-S-1, from 2016 – 2019, there were 81 vertically integrated electric utility decisions by public service commissions resulting in a mean approved 9.74% rate of return on common equity. The mean year-to-date 2019 rate of return on common equity is 9.61%, and the median rate of return on equity is 9.73%.

As shown on Exhibit RBH-S-1, during this period there was only one public service commission (the South Dakota Public Service Commission) decision approving a rate of return on common equity below 9.00% for a vertically integrated electric utility (8.75% in May 2019). Public Staff witness Woolridge's DCF analysis produced a rate of return on common equity ranging from 8.55 – 8.95%, adjusted upward for a specific rate of return on common equity recommendation of 9.00% with a 50.00% common equity capital structure component. As shown on Exhibit JRW-8, page 1, the result of the CAPM analysis for the Electric Proxy Group and the Hevert Proxy Group were 7.3% and 7.2%, respectively. These DCF and CAPM results are substantially below the mean allowed rate of return on common equity of 9.74% from 2016 through mid-September 2019.

In summary, the Commission concludes there is substantial evidence supporting the reasonableness of a rate of return on common equity of 9.75%. First, that rate of return is well within the range of recommended returns by the economic experts in this docket of 7.20% to 11.00%. Second, it falls just 36 basis points above the 9.39% mean results of DENC witness Hevert's DCF analysis and below the mean high results of his DCF analysis. Third, it falls within the range of DENC witness Hevert's CAPM results. Fourth, it falls within the results of DENC witness Hevert's ECAPM results. Fifth, it falls only 18 basis points below the lower end of the range of DENC witness Hevert's Bond Yield Plus Risk Premium analysis results. Sixth, it is slightly below the recommended range of DENC witness Hevert (10.00% to 11.00%). Seventh, it falls squarely within the range and very close to the average of recent vertically-integrated electric utility allowed rates of return on common equity nationally.[6] Eighth, it is equal to the lowest rate of return

[6] The Commission determines the appropriate rate of return on common equity based upon the evidence and particular circumstances of each case. However, the Commission believes that the rate of return on common equity trends and decisions by other regulatory authorities, as well as other recent decisions of this

on equity awarded by this Commission in general rate cases for major electric utilities in at least the last 10 years.[7] Ninth, it is 15 basis points lower than DENC's current allowed rate of return on common equity. Tenth, it is supported as the appropriate rate of return on common equity for DENC by all of parties filing rate of return testimony in this proceeding in lieu of the recommendations made by their respective witnesses on this subject, and the stipulated rate of return on common equity of 9.75% is supported by credible filed settlement testimony by the cost of capital witness for DENC. Finally, and without expressly adopting his methodology, it is consistent with witness Phillips' notion that DENC's return should be capped at the average rate of return on common equity approved by other state commissions for the first two quarters of 2019.[8]

These factors lead the Commission to conclude that a 9.75% rate of return on common equity is supported by the substantial weight of the evidence in this proceeding. However, to meet its obligation in accord with the holding in *Cooper I*, the Commission will next address the impact of changing economic conditions on customers.

In this case, all parties had the opportunity to present the Commission with evidence concerning changing economic conditions as they affect customers. The testimony of witnesses Hevert and Woolridge, 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 common equity estimates.

Public Staff witness Woolridge agreed with DENC witness Hevert that economic conditions have improved in North Carolina. He pointed out that while the State's unemployment rate has fallen by one-third since its peak in the 2009-2010 period and is slightly below the national average of 3.90%, the unemployment rate in DENC's service territory is 4.95%, over 100 basis points higher than the national and North Carolina averages. Witness Woolridge also noted that North Carolina's residential electric rates

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Commission, 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 common 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 common equity significantly higher than other utilities of comparable risk would result in customers paying more than necessary.

[7] *See* Docket Nos. E-2, Subs 1023 and 1142; E-7, Subs 909, 989, and 1146; and E-22, Subs 459, 479, and 532.

[8] Witness Phillips' proposal was a cap at 9.57% based on the first and second quarter average rates of return reported by RRA. However, witness Phillips included distribution-only electric utilities, which are not appropriate. DENC witness Hevert's rebuttal testimony explained that the results reported by Mr. Phillips were skewed by the Otter Tail decision, and a better measure was the median rate of return on common equity authorized for vertically-integrated utilities in 2019 through August 2019 of 9.73%, as opposed to the mean of 9.61%. The Commission finds the use of vertically-integrated electric utilities to be a more comparable measure, as well as the more current data.

are below the national average; however, its median household income is more than 10% below the U.S. norm.

Based upon the general state of the economy and the continuing affordability of electric utility service, and after weighing and balancing factors affected by the changing economic conditions in making the subjective decisions required, the Commission concludes that the stipulated rate of return on common equity of 9.75% will not cause undue hardship to customers even though some will struggle to pay the increased rates resulting from the Stipulations. When the Commission's decisions are viewed as a whole, including the decision to establish the rate of return on common equity at 9.75%, the Commission's overall decision fixing rates in this general rate case results in lower rates to consumers in the existing economic environment.[9]

The many Commission-approved adjustments reduced the revenues to be recovered from customers and the return to be paid to equity investors. Some adjustments reduced the authorized rate of return on investment financed by equity investors. These adjustments have the effect of reducing rates and providing rate stability to consumers (and return to equity investors) in recognition of the difficulty some consumers will have paying increased rates in the current economic environment. While the equity investor's cost was calculated by resort to a rate of return on common equity of 9.75% 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 the 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, and thus, inure to the benefit of consumers' ability to pay their bills in this economic environment.

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

Considering the changing economic conditions and their effects on DENC's customers, the Commission recognizes the financial difficulty that an increase in DENC's

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[9] The Commission notes that consumers pay "rates," a charge in cents per kilowatt-hour (kWh) for the electricity they consume. They do not pay a "rate of return on common equity," though it is a component of the Company's cost of providing service which is built into the charge per kWh. Investors are compensated by earning a return on the capital they invest in the business. Per the Commission determination of the rate of return on common equity in this matter, investors will have the opportunity to be paid in dollars for the dollars they invested at the rate of 9.75%.

rates may create for some of DENC's customers, especially low-income customers. As shown by the evidence, relatively small changes in the rate of return on common equity have a substantial impact on a utility's base rates. Therefore, the Commission has carefully considered changing economic conditions and their effects on DENC's customers in reaching its decision regarding DENC's approved rate of return on common equity.

The Commission also recognizes that the Company is in a significant construction mode, and much of the associated investment is for generation, transmission, and distribution infrastructure to benefit DENC's customers, as well as in response to recent increases in environmental compliance costs and other operating expenses. The need to invest significant sums to serve its customers requires the Company to maintain its creditworthiness in order to compete for large sums of capital on reasonable terms. The Commission must weigh the impact of changing economic conditions on DENC'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. Thus, the Commission finds and concludes that such capital investments by the Company provide significant benefits to all of DENC's customers.

The Commission concludes in the exercise of its independent judgment and discretion that a 9.75% rate of return on common equity is supported by the evidence and should be adopted. The hereby approved rate of return on common equity appropriately balances the benefits received by DENC's customers from DENC'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 (which benefits are symbiotically linked to the Company's ability to compete in the equity capital market to access capital on reasonable terms that will be fair to ratepayers) with the difficulties that some of DENC's customers will experience in paying DENC's adjusted rates. The Commission further concludes that a 9.75% rate of return on common equity will allow DENC to compete in the market for equity capital, providing a fair return on investment to its investor-owners and, the lowering of the rate from the requested 10.75% to 9.75% has the effect of lowering the cost of service which forms the basis the rates the ratepayers must pay for service. Accordingly, the Commission concludes, taking into account changing economic conditions and their impact on customers that the approved rate of return on common equity will result in the lowest rates constitutionally permissible in this proceeding.

Finally, in approving the 9.75% rate of return on common equity, the Commission gives significant weight to the stipulations and the benefits that they provide to DENC's customers, which the Commission is obliged to consider as an independent piece of evidence under the Supreme Court's holding in *CUCA I*.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 17-26

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

The Company and the Public Staff agreed to certain cost of service adjustments addressed in the testimony of Public Staff witness Johnson, the rebuttal testimony of Company witness McLeod, and as further negotiated by the Stipulating Parties. These adjustments are shown on Settlement Exhibit I of the Public Staff Stipulation and are each described below. The resolution of the various adjustments as reflected in the Public Staff Stipulation should be viewed holistically as the result of the give and take negotiations between the Stipulating Parties, rather than as a separate agreement of each Stipulating Party on the amount adjusted in each of the adjustments.

Updates Through June 30, 2019

The Company provided actual updates to certain revenues, expenses and investments through June 30, 2019, as evidenced through supplemental testimony filed August 5, 2019, and second supplemental testimony filed on September 12, 2019, by the Company. The Public Staff and the Company adjusted several of these updates, as reflected in the Public Staff Stipulation. No party took issue with any of these updates. The Commission concludes that these updates are just and reasonable and should be included in rates.

Greensville CC Costs

DENC included in rates for the proceeding approximately $1.3 billion in costs to complete the Greensville CC. This new baseload CC was placed into service on December 8, 2018 and has a capacity of approximately 1,588 MW. Tr. vol. 4, 171. In its testimony, DENC requested that the incremental costs incurred from the time this major new generating facility was placed into service in December 2018 until such time as the costs will be reflected in the base non-fuel rates approved in this proceeding be deferred and amortized over a three-year period beginning with the effective date the Commission approves new rates in this proceeding. Tr. vol. 4, 276.

No party provided testimony challenging the allowance of the deferral for the Greensville CC, nor did any party disagree with the amortization period requested by the Company. The Commission finds and concludes that the Company's request to defer the costs of the Greensville CC and amortize them over three years is just and reasonable to all parties in light of all the evidence presented.

Executive Incentive Compensation

In his direct testimony, witness McLeod testified that the Annual Incentive Plan (AIP) represents at-risk compensation paid out to Company employees only upon meeting certain operation and financial goals during the plan year. He stated that the Company made an adjustment that provided for 100% of the plan target instead of the 120% payout that occurred during the test year. Tr. vol. 4, 267.

In her testimony, Public Staff witness Johnson described the Company's AIP and Long-Term Incentive Plan (LTIP) and how eligible employee's performance is evaluated by the Company and what metrics are used in determining an employee's compensation under one or both of the plans. Witness Johnson testified that she adjusted the allowable costs of AIP to exclude incentive amounts that were based on financial metrics, which are closely tied to EPS, as the AIP as a whole is funded based on a consolidated EPS. Witness Johnson removed amounts related to all executive-level employees because she claimed that those employees' goals align with shareholders' interests. Finally, witness Johnson adjusted the LTIP costs allowed to exclude Performance Shares because the Public Staff believes that the metrics used in calculating Performance Shares provide direct benefits to shareholders rather than ratepayers. Tr. vol. 6, 19-20.

The Public Staff Stipulation provides for the removal of 50% of the costs associated with the Company's executive incentive plan that were based on financial metrics and otherwise retained the Company's proposal. The Commission finds and concludes that the Public Staff Stipulation's treatment of the incentive plan costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Employee Severance Program Costs

In his direct testimony, witness McLeod testified that the Company made an adjustment to include a normalized level of employee severance costs in the cost of service based on the Company's historical experience over the past 24 years. He explained that since 1994 there were five major corporate-wide severance programs which resulted in an average of approximately one every five years. Tr. vol. 4, 266-67.

In his supplemental testimony, witness McLeod explained that in March 2019, the Company announced the Voluntary Retirement Program (VRP) for employees that meet certain age and service requirements. Witness McLeod stated that the VRP was offered to employees of nearly all DEI affiliates, including DENC and Dominion Energy Services, Inc. (DES), and is expected to reduce total workforces during the remainder of 2019 and 2020. He also testified that the VRP is expected to result in a cost savings due to efficiencies gained and confirmed that the Company's supplemental filing incorporated the VRP severance costs as well as the savings through adjustments to employee salaries and wages, benefits, and AIP costs. Witness McLeod further testified that the revenue requirement presented in the Company's supplemental filing has comprehensively incorporated the severance costs and savings associated with the VRP. Additionally, Witness McLeod updated the employee severance program normalization adjustment to include VRP-related severance costs. During the period 1994 through 2019, there were six major corporate-wide severance programs instituted by the Company, resulting in an average of approximately one every 4.17 years. Tr. vol. 4, 305, 311.

In her testimony, witness Johnson stated that the Public Staff would typically include a normalized level of employee severance program costs and use the actual costs of the Company's latest corporate-wide severance program, amortized over a reasonable period of time. However, the circumstances in this docket are distinguishable. Public Staff witness Johnson took exception with using VRP severance costs in the employee severance program cost adjustment because she claimed these costs "appear to be closely linked" to the DEI and SCANA merger approved by the Commission in 2018. *See* Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, *Joint* Application *of Dominion Energy, Inc., and SCANA Corporation to Engage in a Business Combination Transaction*, Nos. E-22, Sub 551, G-5, Sub 585 (N.C.U.C. Nov. 19, 2018) (SCANA Merger Order). Witness Johnson acknowledged that the Company reflected a reduction to salaries and wages, benefits, AIP, and payroll taxes in its supplemental filing as a result of the VRP but disagreed with including the VRP severance costs in the normalized employee severance program calculation. Witness Johnson claimed that the VRP severance costs should be considered "integration costs" as defined in the SCANA Merger Order and pursuant to that order, integration costs should not be included for ratemaking purposes. Witness Johnson proposed retaining the existing normalized level of employee severance costs that was calculated and approved in the 2016 Rate Case. Tr. vol. 6, 20-24.

For purposes of this proceeding, the Public Staff Stipulation provides for a reduction in the revenue requirement in the amount of $304,000 to reflect a downward adjustment for the costs related to the employee severance program requested in this case and a normalization of those costs over 4.5 years. The Commission finds and concludes that the Public Staff Stipulation's treatment of the severance costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

VRP Employee Backfill Costs

In his supplemental testimony, witness McLeod testified that the Company made an adjustment that offset a portion of the VRP savings incorporated in the employee labor and benefits adjustments with a calculated value of salaries and wages for backfilled positions. Tr. vol. 4, 317.

In her testimony, Public Staff witness Johnson made an adjustment to remove the 582 planned positions for both DENC and DES that the Company intended to fill as a result of the VRP. Witness Johnson explained that because these positions have not actually been filled, the costs of those positions should not be included in this proceeding. Witness Johnson explained that should the Company hire any of these employees and provide supporting documentation, up to the close of the hearing in this docket, then she would update her testimony accordingly after investigation and verification that the employees had been hired. Tr. vol. 6, 24.

For purposes of this proceeding, the Public Staff Stipulation provides for an adjustment to the requested revenue requirement for the employee severance program as described above and for the Public Staff's withdrawal of its proposed adjustment for the related VRP backfill costs. The Commission finds and concludes that the Public Staff Stipulation's treatment of the employee backfill costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Storm Restoration Expense

In his direct testimony, witness McLeod explained that it is appropriate to include a normalized level of storm expense in the cost of service for ratemaking purposes given the unpredictable nature of storm activity that can cause a material level of expense in a short period of time. The Company used a historical average of storm activity and cost during the nine years of 2010–2018 in determining its normalized level of expense. Tr. vol. 4, 268.

In her testimony, Public Staff witness Johnson made an adjustment to the Company's normalized level of major storm restoration expenses by calculating the average costs for the last ten years instead of nine as used by the Company. Witness Johnson stated that a ten-year average was consistent with the method used in the most recent rate cases for DEC and DEP in Docket Nos. E-7, Sub 1146 and E-2, Sub 1142, respectively. Tr. vol. 6, 25-26.

For purposes of this proceeding, the Public Staff Stipulation provides for a reduction in the revenue requirement in the amount of $81,000 to reflect a downward adjustment for the storm costs requested in this case. The Commission finds and concludes that the Public Staff Stipulation's treatment of the storm restoration costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Advertising Expense

In his direct testimony, witness McLeod testified that the Company made an adjustment to eliminate all promotional advertising expenses from the test year. Tr. vol. 4, 269.

In her testimony, Public Staff witness Johnson testified that the Company included instructional advertising that appears to be related to public notices specifically related to Virginia jurisdictional matters. The Public Staff made an adjustment to eliminate those public notices that do not appear to relate to DENC ratepayers. Tr. vol. 6, 26.

For purposes of this proceeding, the Public Staff Stipulation provides for a reduction in the revenue requirement in the amount of $12,000 to reflect a downward adjustment for the advertising costs request in this case. The Commission finds and concludes that the Public Staff Stipulation's treatment of the advertising costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Executive Compensation

In his direct testimony, witness McLeod testified that the Company made an adjustment to remove 50% of the compensation of the three executives with the highest level of compensation allocated to DENC during the test year. Tr. vol. 4, 267.

In her testimony, Public Staff witness Johnson made an adjustment to also remove 50% of the compensation and benefits of the fourth executive with the highest level of compensation allocated to DENC during the test year. She claimed that executives' duties and compensation encompass a substantial amount of activities related to shareholder interests and therefore some of their compensation and benefits should be borne by shareholders. Tr. vol. 6, 26-28.

For purposes of this proceeding, the Public Staff Stipulation provides that the Stipulating Parties agreed to accept the Public Staff's proposed adjustment to executive compensation costs. The Commission finds and concludes that the Public Staff Stipulation's treatment of the executive compensation costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Non-fuel Variable Operation and Maintenance Expense Displacement

In his direct testimony, witness McLeod testified that the Greensville CC began commercial operation in December 2018 and the Company then began incurring ongoing operation and maintenance (O&M) expenses associated with running the facility. The Company proposed an adjustment to annualize non-labor O&M expense based on projected average monthly expenses during 2019. Witness McLeod also explained the Company's adjustment to amortize the deferred costs, including a return on investment, associated with the facility as requested in the Company's petition filed on March 29, 2019, in Docket No. E-22, Sub 566. Witness McLeod stated that the Company is requesting that the incremental costs incurred from the time the facility was placed into service until the time costs will be reflected in the base non-fuel rates approved in this proceeding be deferred and amortized over a three-year period beginning with the effective date of rates approved in this proceeding. Tr. vol. 4, 266, 276.

In her testimony, Public Staff witness Johnson adjusted the non-fuel variable O&M expenses to prevent the inclusion in cost of service of more than an annual level of these types of expenses as the Company made pro forma adjustments to include the full cost of Greensville CC in the cost of service, including adding incremental non-fuel variable O&M expenses to reflect a full year of operations. Witness Johnson testified that, with the addition of Greensville County CC, other plants in DENC's fleet will operate less frequently, and thus incur fewer non-fuel variable O&M expenses. Therefore, the Public Staff adjusted non-fuel variable O&M expenses to prevent the inclusion in cost of service of more than an annual level of these types of expenses. Tr. vol. 6, 29-30.

The Public Staff Stipulation provides for a reduction in the revenue requirement in the amount of $142,000, representing non-fuel variable O&M expense displacement. The Commission finds and concludes that the Public Staff Stipulation's treatment of these non-fuel O&M costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Lobbying Expenses

In her testimony, Public Staff witness Johnson made an adjustment to remove internal and external lobbying expenses recorded above the line. She explained that she reviewed job descriptions of employees, both registered and non-registered lobbyists, that performed lobbying activities and applied a "but for" test for reporting lobbying costs as used in a State Ethics Commission opinion dated February 12, 2010. As a result, witness Johnson stated that she excluded not only costs for direct contact with legislators, but also costs for other activities preparing for or surrounding lobbying that would not have occurred but for the lobbying itself. Tr. vol. 6, 30-31.

For purposes of this proceeding, the Public Staff Stipulation provides for a reduction in the revenue requirement in the amount of $42,000 to reflect a downward adjustment for the lobbying costs requested in this case. The Commission finds and concludes that the Public Staff Stipulation's treatment of the lobbying costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Uncollectible Expense

In his direct testimony, witness McLeod testified that the Company adjusted its uncollectible expense based on a historical average uncollectible expense rate. Tr. vol. 4, 269.

In her testimony, Public Staff witness Johnson testified that the Company used data from 2014-2018 to calculate its average uncollectibles amount. Public Staff witness Johnson stated that in 2014 the Company changed its write-off and collections policies for customers with medical certifications, and prior to 2014 the Company did not include these customers in its determination of the reserve for uncollectibles. Witness Johnson explained the result of including these customers now created a $12.1 million credit accounting adjustment in 2014, on a total system level, to its reserve for uncollectibles accounts, with a charge to uncollectibles expense, in order to establish an initial reserve for customers with medical certificates. Witness Johnson testified that the Public Staff adjusted this amount by only calculating the average uncollectibles based on 2015–2018 data. Tr. vol. 6, 31-32.

For purposes of this proceeding, the Public Staff Stipulation provides that the Company accepted the Public Staff's proposed adjustment to uncollectibles costs, resulting in a reduction of $238,000 in the Company's revenue requirement. The Commission finds and concludes that the Public Staff Stipulation's treatment of the uncollectibles costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Skiffes Creek

Company witness Bobby McGuire testified on direct that DENC invests in its electric transmission system to ensure reliability and ongoing compliance with the North American Electric Reliability Corporation (NERC) reliability standards and requirements, address load growth, and repair or replace aging infrastructure, and explained that these investments ensure the Company's continued ability to provide safe, reliable, and economical power to all of its customers. He stated that DENC has invested approximately $268 million in electric transmission projects located in North Carolina during the period of 2016–2018. Witness McGuire further explained that the Company's electric transmission system investments completed in Virginia also provide benefits to North Carolina customers. Tr. vol. 6, 366-69.

In his testimony, Public Staff witness David Williamson provided an overview of the Surry-Skiffes Creek 500-kV transmission project that crosses the James River in Virginia, including the need for the project and the regulatory approvals needed for the project from the Virginia State Corporation Commission, the Army Corps of Engineers, and others. Witness Williamson stated that the Public Staff takes the position that the mitigation costs for the project were not incurred for the purpose of constructing or operating the project and do not provide additional benefits to the Company's North Carolina retail customers, so those costs should not be recovered from the Company's North Carolina customers. Specifically, witness Williamson asserted that the mitigation costs, which are predominantly reflected in a Memorandum of Agreement signed by multiple stakeholders that participated in the project's permitting process, should be excluded from the Company's revenue requirement consistent with Commission precedent set in the Company's 2012 Rate Case, Docket No. E-22, Sub 479, involving a disallowance of the incremental costs associated with undergrounding three transmission lines in northern Virginia largely for aesthetic purposes. Tr. vol. 6, 447-61.

In her testimony, Public Staff witness Johnson made an adjustment to remove the costs of the Skiffes Creek project mitigation as explained by Witness Williamson. Tr. vol. 6, 33.

The Public Staff Stipulation provides that the revenue requirement should be reduced in the amount of $153,000 to reflect a downward adjustment for the Skiffes Creek mitigation costs requested in this case. The Commission finds and concludes that the Public Staff Stipulation's treatment of the Skiffes Creek mitigation costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Outside Services

In her testimony, Public Staff witness Johnson testified that the Public Staff reviewed costs for outside services, and that the Public Staff's investigation revealed charges that were related to legal services for certain expenses that were allocated to DENC that should have been directly assigned to other jurisdictions. Witness Johnson stated that DENC ratepayers should be charged only the reasonable costs of providing electric service to North Carolina retail customers. Tr. vol. 6, 33-34.

The Public Staff Stipulation provides that the revenue requirement should be reduced in the amount of $177,000 to reflect a downward adjustment for the outside services costs requested in the case. The Commission finds and concludes that the Public Staff Stipulation's treatment of the outside services costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Mount Storm Fuel Flexibility Project

In his supplemental testimony, Company witness McLeod proposed to defer as a regulatory asset costs associated with the abandoned Coal Yard Fuel Flexibility Project (CYFFP) at the Company's Mount Storm Power Station (Mount Storm) that was canceled due to changing market conditions, decreased power prices, and lower capacity factors, and coal consumption at Mount Storm. The Company abandoned the project in May 2019, resulting in an impairment of construction costs incurred on the project totaling $62.4 million (system-level). Witness McLeod proposed to defer the portion of the CYFFP costs allocable to the Company's North Carolina jurisdiction to be amortized over a three-year period. Tr. vol. 6, 316.

In his testimony, Public Staff witness Thomas provided an overview of the Mount Storm CYFFP, which was undertaken to allow the facility to receive 100% of its coal supplies by rail in the event of problems with truck deliveries. Due to quality differences between truck and rail delivered coal and the emissions limits established by Mount Storm air permits, as well as the specific boiler design characteristics of the Mount Storm units, coal blending facilities were required. Witness Thomas testified that DENC originally planned to construct four coal stacking tubes and a dry coal storage enclosure, and to make significant changes to its rail system, along with supplementary fire suppression systems. He testified that not until the adjustment was included in DENC's supplemental filing did the Public Staff become aware of the project and then have an opportunity to review the costs and underlying analyses. Witness Thomas testified that the Public Staff analyzed the Company's financial analyses used in determining the viability of the CYFFP and expressed concerns with the Company's decision-making with respect to future coal prices used in its analyses, contract negotiations with the local trucked coal supplier, and the projected capacity factor of the Mount Storm facility used in its analyses. He also expressed concerns that significant commitments and associated expenditures with the project appear to have been made prior to completion of detailed engineering work, and relatively little cost-benefit analyses were performed until 2014, three years and

$2.1 million into the project. Witness Thomas concluded that based on his review of forecast data in the Company's past IRPs, the Company should have been more aware of market conditions within both the natural gas and coal markets, and the increased risk that the project would not deliver the expected benefits. In addition, he stated that the Public Staff believes that the 2014 cost-benefit analysis justifying the project had significant shortcomings and was not a reasonable or prudent analysis to justify a project that, at the time, had an estimated cost of $116 million. Witness Thomas recommended that expenditures on the CYFFP after the 2014 analysis should be disallowed for a total of $60,179,000 system-wide. Tr. vol. 6, 504-26.

In her testimony, Public Staff witness Johnson made an adjustment to remove certain costs associated with the project as recommended by Public Staff witness Thomas that are allocable to the Company's North Carolina jurisdiction. Tr. vol. 6, 34-35.

The Public Staff Stipulation provides that 50% of the Mount Storm impairment costs should be removed with the remaining portion amortized over 2.75 years. The Commission finds and concludes that the Public Staff Stipulation's treatment of the Mount Storm CYFFP costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

NUG Contract Termination Expense

In his supplemental testimony, witness McLeod testified that the Company had a long-term power and capacity contract with a coal-fired NUG with an aggregate summer generation capacity of approximately 218 MW. Witness McLeod stated that the plant had been, and was expected to remain, generally uneconomical in the PJM Interconnection, LLC (PJM), energy market, and therefore, ran infrequently and was not a key resource for DENC nor does it continue fit within DENC's portfolio of increasingly cleaner generation resources. In May 2019, the Company entered into an agreement and paid $135.0 million to terminate the contract, effective April 2019. Given the magnitude of the termination fee and the significant capacity savings going-forward, witness McLeod proposed to defer the North Carolina jurisdictional portion of the termination fee to be amortized over the original remaining term of the contract (32 months — April 2019 through November 2021).

In her testimony, Public Staff witness Johnson testified that the Public Staff made an adjustment to remove approximately $21.4 million from the NUG contract termination expense payment associated with the Company's early contract termination. Witness Johnson explained that her adjustment accounts for the "net amount" of capacity revenue that the Company will be receiving from the PJM capacity market as well as the estimated replacement power costs that will be incurred as a result of the termination of the contract. Tr. vol. 6, 35-36.

The Public Staff Stipulation provides that the Company accepted the Public Staff's proposed adjustment to the NUG contract termination expense. The Commission finds and concludes that the Public Staff Stipulation's treatment of the NUG contract termination expense is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Impact on Expenses of Changes in Usage and Number of Customers

In her testimony, Public Staff witness Johnson testified that the Company adjusted revenues for the change in kWh sales and the number of customers due to customer growth, changes in usage, and weather normalization, but did not make a corresponding adjustment to recognize the changes in the non-fuel variable O&M expenses, which vary due to the change in kWh sales. She also explained that the Company did not make a corresponding adjustment to customer-related expenses to reflect the change in the number of customers. Witness Johnson adjusted these expenses to reflect the changes in kWh sales and the number of billings proposed by the Company in its customer growth, usage, and weather normalization adjustments. Tr. vol. 6, 36-37.

The Public Staff Stipulation provides that the revenue requirement should be reduced in the amount of $90,000 to reflect updated and corrected customer growth, usage, and weather normalization numbers. The Commission finds and concludes that the Public Staff Stipulation's treatment of these costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Inflation

In his direct testimony, witness McLeod testified that the Company adjusted O&M expenses in the cost of service not adjusted elsewhere by increasing them with an inflation factor. He explained that the inflation factor was measured as the difference of the Producer Price Index – Finished Goods less Food and Energy (PPI) between the midpoint of the test year and the end of the period from January 1, 2019, to June 30, 2019 (Update Period). Tr. vol. 4, 270.

In his supplemental testimony, witness McLeod updated the inflation adjustment to reflect the actual PPI for June 2019. *Id*. at 313.

Public Staff witness Johnson stated in her testimony that she made additional adjustments in the calculation of the inflation adjustment to reflect the Public Staff's adjustments to the O&M expenses subject to inflation. Tr. vol. 6, 37.

For purposes of this proceeding, the Public Staff Stipulation provides that the revenue requirement should be reduced in the amount of $7,000 to reflect updated data related to inflation. The Commission finds and concludes that the Public Staff Stipulation's treatment of the inflation expense is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Customer Growth, Usage, and Weather Normalization

In his direct testimony, witness McLeod testified that the Company annualized base non-fuel tariff revenues based on projected customer levels and weather-normalized usage as of June 30, 2019. He explained that this adjustment was a net reduction to revenue, primarily reflecting the annualized impact of a return to normal weather on customer usage. In his direct testimony, Company witness Haynes testified that the adjustments for customer growth, increased usage, and weather normalization are incorporated in Form E-1 Item 42.a, and that the methodologies used to calculate these adjustments are consistent with those approved by the Commission in the 2016 Rate Case. Tr. vol. 4, 259, 411.

In their supplemental testimony, witnesses McLeod and Haynes updated the calculations based on actual customer growth and usage during the Update Period. Witness Haynes testified that the weather normalization and usage adjustments should not include Basic Customer Charge revenues in the calculation of the average revenue per kWh applied to the sum of these kWh adjustments. Witness Haynes stated that he made this change in the calculation. *Id.* at 307, 420.

In his second supplemental testimony, witness Haynes presented an additional update to the customer growth and usage adjustments to the level of customers used in the calculation. The update is consistent with how customer levels were calculated in the 2016 Rate Case. In his second supplemental testimony, witness McLeod updated the calculations based on the annualized level of customer usage presented in witness Haynes' second supplemental testimony. *Id.* at 430.

The Public Staff Stipulation provides that the Stipulating Parties agreed to increase the revenue requirement in the amount of $49,000 to reflect the Company's updated and revised kWh sales. The Commission finds and concludes that the Public Staff Stipulation's treatment of these costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Cash Working Capital

In his direct testimony, witness McLeod testified that the Company made an adjustment to its cash working capital (CWC) based on a lead/lag study prepared using calendar year 2017 data. He further explained that the CWC requirement included in the cost of service per books is adjusted based on the adjusted CWC requirement as determined for regulatory purposes. *Id.* at 279.

In his supplemental testimonies, Witness McLeod proposed updates to the CWC adjustment to reflect changes in lead/lag days, and the impacts of the various accounting adjustment revisions and updates to the cost of services. Tr. vol. 4, 297, 329.

Public Staff witness Johnson testified that the Public Staff adjusted CWC under present rates by (1) showing the working capital impact of revenues separate from expenses for presentation purposes, and also (2) reflecting all of the other Public Staff adjustments. Witness Johnson also adjusted CWC for the effect of the Public Staff's proposed revenue decrease. Tr. vol. 6, 38-39.

For purposes of this proceeding, the Public Staff Stipulation provides that the revenue requirement should be reduced in the amount of $83,000 and $282,000 to reflect changes in CWC under present and proposed rates, respectively. The Commission finds and concludes that the Public Staff Stipulation's treatment of these costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

DES Office Building

In his direct testimony, witness McLeod testified that during the second quarter of 2019, the Company planned to occupy a new office building, 600 Canal Place, and made an adjustment to annualize the amount of costs for DENC's direct occupancy of the new building, as well as DENC's billable portion of expenses from DES based on DES' existing methodology to bill its office space and equipment expenses to affiliates. He explained that the Company planned to cease occupying its existing office space after the move and the adjustment reflects the net effect of the increased annual expenses between the two offices. Tr. vol. 4, 267-68.

In his supplemental direct testimony, witness McLeod testified that, at the time of the of the Application, occupation of 600 Canal Place by DENC and DES employees was expected to begin during the second quarter of 2019. Witness McLeod explained that DES and the Company began occupying the new building in July 2019 and DES will begin making lease payments in August 2019. The Company's adjustment updated the new lease expense budget for calendar year 2019 and witness McLeod stated that the expense will be updated again in September 2019 after the actual lease payment is incurred for August 2019. Witness McLeod's second supplemental testimony updated this accounting adjustment based on the actual corporate-level costs for the month of August 2019, the month in which the lease payments commenced. Tr. vol. 4, 312, 331.

In her testimony, Public Staff witness Johnson testified that the Public Staff was awaiting additional documentation pertaining to the Company's adjustment to reflect the new office building. Witness Johnson explained that the Public Staff will need additional time to review the adjustments once filed by the Company as they relate to the new office building. *Id.* at 40-41.

For purposes of this proceeding, the Public Staff Stipulation provides that the revenue requirement should be reduced in the amount of $720,000 to reflect the updated, actual costs of the Company's new office building. The Commission finds and concludes that the Public Staff Stipulation's treatment of the office building costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Depreciation

In his direct testimony, witness McLeod testified that the Company made an adjustment to annualize the depreciation expense based on projected plant in service as of June 30, 2019, and the composite depreciation rate from the Company's most recent depreciation study. *Id.* at 274.

In his supplemental testimony, witness McLeod updated the depreciation expense based on actual plant in service at the end of the update period. Tr. vol. 4, 317.

In her testimony, Public Staff witness McCullar testified that she participated in field visits of several DENC facilities or project locations, analyzed the Company's most recent depreciation study, and presented the Public Staff's proposed depreciation rates. Witness McCullar's Table One provides a comparison of annual deprecation accrual amounts as proposed by the Company versus as proposed by the Public Staff. The table indicates that the Public Staff and the Company are aligned with respect to steam production plant, nuclear production plant, hydraulic production plant, combined cycle production plant, simple cycle production plant, and general plant. The two parties differed, however, with respect to solar production plant, transmission plant, and distribution plant. Witness McCullar explained that for solar production plant, the Public Staff used updated depreciation schedules that changed the probable retirement year for several solar facilities from 2041 to 2051. Public Staff witness McCullar also explained that the differences in transmission plant and distribution plant depreciation as a difference between the Public Staff's and the Company's proposed future net salvage accrual amounts, as the Public Staff proposed less accelerated future net salvage amounts than the Company. Tr. vol. 6, 476-94.

For purposes of this proceeding, the Public Staff Stipulation provides that the Public Staff accepted the Company's proposed depreciation rates as filed in its Application. Subject to the qualifications and direction provided in Findings of Fact Nos. 56-58 and the discussion thereunder relating to the costs of removal portion of depreciation allowance, in all other respects the Commission finds and concludes that the Public Staff Stipulation's treatment of the depreciation costs is appropriate and reasonable in this case when considered within the context of the Public Staff Stipulation as a whole.

Retirement of Cold Reserve Units

In his direct testimony, Company witness Mitchell testified that, in an effort to reduce costs, uneconomical units that were previously placed in a cold reserve state and are not currently operating will be retired by the end of March 2019. According to witness Mitchell, these older, less efficient units are unable to compete in the current energy market and have been displaced by cleaner burning natural gas facilities, as well as utility-scale solar. Witness Petrie explained in his direct testimony that ten of these units were older, less efficient units that were placed in a "cold reserve" state in 2018. These units included Bellemeade Power Station, Bremo Power Station Units 3 and 4, Chesterfield

Power Station Units 3 and 4, Mecklenburg Power Station Units 1 and 2, Pittsylvania Power Station, and Possum Point Power Station Units 3 and 4, all of which were retired from service effective March 31, 2019. Witness Petrie also testified that the Company plans to retire Possum Point Unit 5 on May 31, 2021.

In his supplemental testimony, witness McLeod explained that, as a result of these early retirements, the Company recorded an impairment charge of $307.1 million, representing the remaining net book value of the units. Related balances in construction work in progress and materials and supplies inventory were written-off as well. Witness McLeod proposed that the Company amortize the impairment cost for the ten units formerly in cold reserve over a ten-year levelized basis and the materials and supplies inventory over a three-year period. He also proposed eliminating the O&M expense and materials and supplies inventory for the ten units formerly in cold reserve. Finally, witness McLeod proposed reestablishing the Possum Point Unit 5 net book value and depreciation expense for ratemaking purposes as the unit has not yet been physically retired from service. He requested that any costs incurred during the decommissioning of these facilities after the update period be deferred for review in the Company's next base rate case, consistent with the treatment of decommissioning costs for the Chesapeake Energy Center in the 2016 Rate Case. Tr. vol. 4, 302-04, 348.

The Commission notes that it appears from the evidence presented that the amount of the impairment charge recorded by the Company on account of the units decommissioned effective March 31, 2019, does not include costs of remediation and closure of coal ash management units associated with the units in cold reserve. Accordingly, the Commission finds and concludes that the Company's treatment of costs associated with the retirement of cold reserve units is appropriate and reasonable in this case so far as it goes. The Company should consider the Commission's Findings of Fact Nos. 56-58 and the discussion thereunder relating to the costs of removal portion of depreciation allowance when recording impairment charges due to early retirements in the future.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 27-31

The evidence supporting these findings of fact and conclusions is found in the Company's verified Application and Form E-1, the exhibits and testimony of Company witnesses McLeod and Haynes, the exhibits and testimony of Public Staff witness Boswell, the exhibits and testimony of CIGFUR witness Phillips, the Public Staff Stipulation, and the entire record in this proceeding.

Summary of the Evidence

In his direct testimony, DENC witness McLeod described the Tax Act and the primary elements of the Tax Act that impact DENC, including a reduction in the federal corporate income tax rate from 35.00% to 21.00%. Witness McLeod noted that the Commission initiated a new generic proceeding in January 2018, in Docket No. M-100, Sub 148 (Sub 148), to address how North Carolina utilities should adjust their North

Carolina jurisdictional cost of service and rates in response to the Tax Act. Witness McLeod testified that by order dated January 3, 2018 in Sub 148 the Commission directed certain utilities, including DENC, to collect the federal corporate income tax expense component of rates on a provisional basis beginning January 1, 2018, pending a final order from the Commission. Witness McLeod described the filings and orders in Sub 148 and explained that DENC implemented a Commission-approved rate reduction to address certain impacts of the Tax Act, as ordered by the Commission in its October 5, 2018 Order Addressing the Impacts of the Federal Tax Cuts and Jobs Act on Public Utilities, issued in Sub 148. Witness McLeod testified that this included an annual revenue reduction of $14.3 million due to a base rate adjustment to reflect the lower federal corporate income tax rate, and approval of a one-time customer bill credit to reflect the return of money collected provisionally under the January 3, 2018 Order for income taxes at the higher tax rate through existing base rates billed since January 1, 2018. The one-time customer bill credits were reflected on customers' bills beginning in the April 2019 billing period for amounts collected provisionally from January 1, 2018 through March 2019.

Witness McLeod testified that for purposes of federal EDIT, the Company established an overall regulatory liability and began amortizing plant-related federal EDIT on its books and records at a system level as a reduction to income tax expense with an effective date of January 1, 2018. Witness McLeod explained that this amortization is being deferred to a regulatory liability account in accordance with the Commission's October 5, 2018 Order. Witness McLeod provided a general overview of federal EDIT and explained that the predominant amount of federal EDIT is associated with utility property depreciation and related book-tax timing differences, which are subject to the Internal Revenue Code's (IRC's) normalization rules. Witness McLeod noted that this EDIT is referred to as "protected" and the Company is required to use the average rate assumption method (ARAM) for purposes of amortizing such EDIT. Witness McLeod provided the federal EDIT balances as of December 31, 2017, at a system level and the portion allocable to the North Carolina retail jurisdiction of $94.1 million (revised to $94.7 million in witness McLeod's supplemental testimony) for plant-protected, plant-unprotected, and non-plant unprotected.

Witness McLeod testified that for ratemaking purposes, the Company has proposed that the effective date of federal EDIT amortization begin on January 1, 2018. He further explained that because the Company is proposing to implement new rates beginning November 1, 2019, that the federal EDIT amortization attributable to the 22-month period of January 1, 2018, through October 31, 2019, would be credited to customers through a one-year decrement rider, Rider EDIT, of $6,909,000. Finally, witness McLeod testified that for periods thereafter, the Company's fully adjusted cost of service includes the income tax benefit arising from annual federal EDIT amortization during the test period, thereby incorporating a going-level of federal EDIT amortization in base non-fuel rates. Witness McLeod proposed an ARAM method to amortize plant-related federal EDIT (both protected and unprotected) and a 30-year amortization period for non-plant, unprotected federal EDIT. Witness McLeod presented the proposed annual amount of federal EDIT amortization for the North Carolina jurisdiction of $2.7 million. Witness McLeod explained that the base non-fuel revenue requirement reflects this amortization providing the customers with an annual revenue benefit of approximately $3.6 million ($2.7 million/74% retention factor). Tr. vol. 4, 290-91.

In DENC witness Haynes' direct testimony, he explained the Company's proposal that the Rider EDIT credit should be allocated to customer classes based upon North Carolina basic (non-fuel) rate revenue annualized based upon current rates for 2018. Witness Haynes testified that the decrement rate will be applied to customer usage beginning with the effective date of the rider and will be in effect for 12 months. Witness Haynes proposed that, prior to the tenth month from the effective date of the rider, the Company will provide an analysis to the Public Staff to evaluate if the total rider credit will be provided at the end of the 12 months. Witness Haynes explained that if there is a deviation between the total rider credit and the projected credit provided to customers, the Company and the Public Staff will work together to develop an adjustment to the Rider EDIT to minimize the deviation over the remaining months of Rider EDIT being in effect. Tr. vol. 4, 401-02.

In his supplemental testimony, witness McLeod summarized DENC's corrections to the allocation of system-level federal EDIT balances and amortization to the North Carolina jurisdiction resulting from revisions to DENC's cost of service study presented by witness Miller. Witness McLeod noted that as a result of the corrections, the North Carolina jurisdictional federal EDIT balance was revised from $94.1 million to $94.7 million. Witness McLeod explained that the total Rider EDIT rate credit, as revised, reflects a slight $1,000 increase from $6,909,000 to $6,910,000. Tr. vol. 4, 296-97, 325-26.

In his testimony, CIGFUR witness Phillips acknowledged DENC's proposal to credit to customers through a one-year rider the federal EDIT amortization attributable to the period January 1, 2018 through October 31, 2019 and stated that EDIT are overpayments that should be returned as soon as possible. Tr. vol. 6, 431.

In her direct testimony, Public Staff witness Boswell recommended three adjustments to the Company's proposed treatment of federal EDIT. First, witness Boswell stated that she agreed with the Company's proposed ARAM utilization for federal protected EDIT but could not calculate this amortization due to a lack of a breakout between protected and unprotected EDIT. Witness Boswell recommended that the Commission require the Company to file schedules illustrating this breakout. Second, witness Boswell stated that she disagreed with the Company's adjustment to include a portion of unprotected EDIT labeled as "plant-unprotected" to be recovered utilizing the ARAM calculation. Instead, witness Boswell recommended including the "plant-unprotected" balance with the non-plant unprotected EDIT and collecting the balance on a levelized basis over a five-year period. Finally, witness Boswell testified that the entire unprotected EDIT balance should be removed from rate base and placed in a rider to be collected from ratepayers over a five-year period. Witness Boswell testified that the Public Staff does not, in theory, object to the Company's proposal to flow back federal protected and unprotected amortization since January 1, 2018, as a one-year levelized rider. Tr. vol. 6, 440-43.

DENC and the Public Staff reached a stipulation on all of the Tax Act-related issues as outlined in Section VIII.A of the Public Staff Stipulation, wherein they agreed that DENC shall implement Rider EDIT to allow for recovery of federal EDIT of $1.2 million on a levelized basis over a two-year period, with a return. The Public Staff Stipulation notes that the $1.2 million is comprised of: (1) the amortization of all unprotected federal EDIT totaling approximately $8.0 million partially offset by (2) the refund of approximately $6.8 million associated with federal EDIT amortization attributable to the 22-month period of January 1, 2018 through October 31, 2019. The Public Staff Stipulation also states that the appropriate revenue level of EDIT to be recovered by DENC is presented on Settlement Exhibit II and that DENC will implement Rider EDIT as described in the stipulation testimony of DENC witness McLeod.

Further, the Public Staff Stipulation states in Section IV.E that the Stipulating Parties agree to reduce the revenue requirement in the amount of $287,000 to reflect the removal of federal unprotected EDIT from rate base, which will be recovered by the Company through a rider as discussed in Section VIII.

In his Stipulation testimony, witness McLeod testified that the Stipulating Parties agreed that the Company would implement Rider EDIT to allow for recovery by DENC of federal EDIT of $1.2 million, comprised of the amortization of all unprotected federal EDIT totaling $8.0 million, partially offset by the refund to ratepayers of approximately $6.8 million associated with federal EDIT amortization attributable to the 22-month period January 1, 2018, through October 31, 2019. Tr. vol. 4, 340.

Discussion and Conclusions

In Ordering Paragraph No. 6 of its October 5, 2018 Order in Sub 148, the Commission ordered:

> That excess deferred income taxes related to the decrease in the federal corporate income tax rate to 21% under the Tax Act for Cardinal, DENC, DEP, Piedmont, and PSNC, as appropriate, shall be held in a deferred tax regulatory liability account until they can be addressed for ratemaking purposes in each utility’s next general rate case proceeding or in three years, whichever is sooner. These amounts will ultimately be returned to customers . . . . Therefore, the Commission concludes that if Cardinal, DENC, DEP, Piedmont or PSNC have not filed an application for a general rate case proceeding by October 5, 2021, each Company shall file its proposal by that date to flow back to its ratepayers both the protected and the unprotected EDIT generated due to the Tax Act. The federal EDIT flow back proposal should include all workpapers that support the proposed calculations. . . . These utilities are hereby required to maintain the deferred tax regulatory liability account previously established and shall not begin amortization of amounts recorded in such accounts pending further order of the Commission.

This proceeding is the first general rate case filed with the Commission by DENC since the October 5, 2018 Order was issued. DENC has complied with the Commission's directive by addressing the Tax Act issues in this rate case that was filed before October 5, 2021. The Company has also complied with the Commission's directive not to begin amortization of North Carolina jurisdictional federal EDIT until further order of the Commission. DENC meets this requirement, given the Company's proposal to begin amortization on January 1, 2018, by proposing to credit the amortization during the 22-month period from January 1, 2018, through October 31, 2019, the effective date of rates in this case, to customers through a decrement rider, Rider EDIT. In addition, for periods thereafter, the Company's cost of service for ratemaking purposes includes the income tax benefit arising from annual federal EDIT amortization during the test period, thereby incorporating a going-level of federal EDIT amortization in base non-fuel rates.

As outlined in Public Staff witness Boswell's testimony, the Public Staff recommended including the "plant-unprotected" federal EDIT balance with the federal unprotected EDIT and collecting the balance from ratepayers through an increment rider to be collected from ratepayers over five years on a levelized basis, with carrying costs. Witness Boswell testified that this recommendation is consistent with previous recommendations of the Public Staff.

The Stipulating Parties agreed that the Company shall implement Rider EDIT to allow for recovery of certain federal EDIT. The Public Staff Stipulation provides that the appropriate level of federal EDIT to be recovered by the Company in this case is $1,214,000 (on a pre-income tax basis), which includes: (1) the amortization of all unprotected federal EDIT totaling approximately $8.0 million partially offset by (2) the refund to ratepayers of approximately $6.8 million associated with federal EDIT amortization attributable to the 22-month period January 1, 2018 through October 31, 2019. Rider EDIT will be implemented to recover certain federal EDIT from ratepayers over a two-year period on a levelized basis, with a return. As reflected on Settlement Exhibit II, Schedule 2, the appropriate amount to be recovered from customers is a total of $1,299,369. Rider EDIT should be calculated and reviewed using the methodology presented in the testimony of DENC witness Haynes.

On September 25, 2019, the Commission issued an Order Requesting Additional Information and ordered that the Public Staff make a filing providing an explanation of why DENC's total unprotected EDIT has a debit balance, as the Commission has not previously seen a debit balance in its consideration of EDIT issues related to the Tax Act. On October 7, 2019, the Public Staff filed a response to this request. The response referenced the testimony and exhibits of Company witness McLeod which provided details regarding the Company's balance of unprotected federal EDIT. Specifically, the Public Staff noted that witness McLeod's testimony and exhibits demonstrate that the largest debit balance for non-plant unprotected EDIT related to pension benefits. The Public Staff stated that it reviewed the causation of the debit balance for the aforementioned account and determined that the debit balance was due to the status of funding for the Company's pension plan. The Public Staff further stated that as of December 31, 2017, the Company's projected benefits obligation from its pension plan was larger than the amount that had been funded for the plan, resulting in a net pension liability on the Company's books. The Public Staff observed that this in turn resulted in a deferred tax asset on the Company's books, and thus an EDIT asset. The Public Staff stated that it submitted a data request to DENC on this matter. The Public Staff maintained that after further discussions with DENC in regard to its response, and in recognition of the fact that different companies may well calculate the split between plant-related protected and unprotected EDIT using different analyses and methods, the Public Staff accepted the Company's division of plant-related EDIT between protected and unprotected components, which results in the unprotected portion having a relatively small debit balance.

Based on all of the evidence of record in this case, the Commission finds that it is appropriate to accept the Public Staff Stipulation concerning the Tax Act issues. The ratemaking treatment of federal EDIT, including Rider EDIT presented in the Public Staff Stipulation, is just and reasonable to all parties in light of all the evidence presented. In reaching its decision, the Commission gives substantial weight to DENC witness McLeod's stipulation testimony.

Further, although not specifically outlined in the Public Staff Stipulation, it is appropriate that in this proceeding DENC's fully-adjusted cost of service includes the income tax benefit arising from the annual amortization of federal protected EDIT during the test year, thereby incorporating a going-level of federal protected EDIT amortization in base non-fuel rates, in accordance with the IRC's normalization rules.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 32-34

The evidence supporting these findings of fact and conclusions is found in the verified Application; the direct testimony and exhibits of Company witnesses Petrie and Haynes; the supplemental testimony of witnesses Petrie, Haynes, and McLeod; the additional supplemental testimony of witness Haynes; the testimony and exhibits of Public Staff witnesses Floyd and Johnson; the Public Staff Stipulation; and the entire record in this proceeding.

Summary of the Evidence

In his direct testimony, Company witness Petrie presented an estimate of DENC's adjusted system fuel expense for the period July 1, 2018 – June 30, 2019, of $1.803 billion, which was used by Company witness Haynes to estimate the anticipated reduction in the fuel factor rate. He also estimated a cumulative fuel under-recovery position for the 12-month test period ending June 30, 2019, of approximately $1–3 million, and described DENC's forecasted fuel expense over-recoveries for the second half of 2019 and how those over-recoveries could offset the expected under-recovery as of June 30, 2019. Tr. vol. 6, 345-50.

Witness Haynes calculated the projected normalized North Carolina jurisdictional average fuel factor and differentiated that rate by voltage for each class. These calculations were consistent with the methodologies used in the Company's 2018 fuel case, except that he updated the class expansion factors for 2018. Witness Haynes also presented DENC's projected EMF and total projected change in its fuel factor to be filed in its 2019 fuel proceeding. Tr. vol. 4, 397-400.

Witness Petrie also testified that the Company evaluated the current Marketer Percentage calculation and updated the calculation based on the PJM State of the Market Reports for 2017 and 2018 using the same averaging method applied in the 2018 Fuel Case and the 2016 Rate Case. Using this method, witness Petrie calculated an updated Marketer Percentage of 71%. Tr. vol. 6, 345-50.

In his direct testimony, witness McLeod testified that adjustments to purchased energy expenses reflect an updated Marketer Percentage of 71% supported by Company witness Petrie. Witness McLeod stated that the base fuel rate revenue requirement in the supplemental filing will reflect the 71% Marketer Percentage. Tr. vol. 4, 245.

In his supplemental testimony, Witness Petrie presented an updated adjusted total system fuel expense for the 12-month period ending June 30, 2019, of $1.78 billion, based on the 71% Marketer Percentage proposed in the Company's Application. Tr. vol. 6, 355-56.

In his direct testimony, Company witness Haynes testified that while the Company's fuel factor is adjusted annually by the Commission between general rate cases, the Commission also resets the Company's base fuel factor in each base rate case as required by subsection (f) of the North Carolina fuel factor statute, N.C.G.S. § 62-133.2. Company witness Haynes proposed to initially set a placeholder base fuel rate for each class based on the fuel factor approved in the Company's 2018 fuel adjustment case, Docket No. E-22, Sub 558 (2018 Fuel Case). He further testified to the Company's proposal to set Rider A – Fuel Cost Rider to zero beginning November 1, 2019, and to use the fuel rate as approved in the 2018 Fuel Case, differentiated by class, as the placeholder base fuel rate in each of the rate schedules. Witness Haynes stated that the Company planned to update the placeholder base fuel rate after the Company filed its annual fuel factor application in August 2019. Tr. vol. 4, 397-98.

In his supplemental testimony, Witness Haynes updated the placeholder base fuel rate and proposed a new rider, decrement Rider A1, which the Company planned to file in its August 2019 fuel factor application. Witness Haynes testified that because the Company was anticipating an over-recovery of fuel expenses for the period of July 2019 to December 2019, and to mitigate the effect of the November 1, 2019, non-fuel base rate increase on customers' rates, the Company was proposing to implement a three-month decrement rider, Rider A1. Witness Haynes testified that Rider A1 would allow for a seamless, no impact transition of total fuel rates between November 1, 2019, and February 1, 2020, based on the Company's anticipated fuel factor filing. Finally, he explained that the Company anticipated making an additional supplemental update in this proceeding to calculate the revised base fuel rates by customer class using the information in the Company's August 2019 fuel factor application. Tr. vol. 4, 416, 423-24.

In his additional supplemental testimony, witness Haynes used the updated adjusted total system fuel expense presented in the Company's 2019 fuel factor filing to calculate a jurisdictional average base fuel factor of 2.092¢/kWh. He also used the revised Rider A rate of zero, to be effective on November 1, 2019, consistent with the Company's 2019 fuel factor filing. Finally, witness Haynes explained that the amount used for decrement Rider A1 was based on an estimation that the Company will over-recover fuel expenses from July through December 2019 by approximately $11.8 million, with the rider being the difference between the proposed February 1, 2020, Fuel Rider B EMF Rate and the current EMF Rider B rates that became effective on February 1, 2019. Witness Haynes stated that including the proposed base fuel rate, the proposed Fuel Rider A re-set to 0.000¢/kWh, the proposed Rider A1 rates, and the present EMF Rider B, the Company proposed to implement a jurisdictional average total fuel rate of 2.105¢/kWh on November 1, 2019, a decrease of 0.425¢/kWh compared to the present jurisdictional average total fuel rate of 2.530¢/kWh. Tr. vol. 4, 428-31.

Public Staff witness Floyd testified the Public Staff did not have any concerns with the Company's proposed fuel rates for purposes of this proceeding and that the Public Staff would address any concerns with fuel rates in the 2019 Fuel Case proceeding in Docket No. E-22, Sub 579. Witness Floyd also stated that the Public Staff did not oppose implementing the Company's proposed total fuel rate as part of the interim rates on November 1, 2019, along with the proposed decrement Rider A1. Tr. vol. 6, 81-83.

In her testimony, Public Staff witness Johnson adjusted the fuel clause expense to reflect the base fuel rate and Rider A as set forth in the additional supplemental testimony of DENC witness Haynes, and recommended by Public Staff witness Floyd, subject to the outcome of the Company's currently ongoing fuel proceeding in Docket No. E-22, Sub 579. Witness Johnson stated that this adjustment resulted in a decrease of $2.155 million from the fuel expense originally included in the Company's Application. Tr. vol. 6, 39.

Section V.A of the Public Staff Stipulation provides that a decrease of $2.155 million in the Company's base fuel revenue requirement, incorporating the base fuel rate and Rider A as set forth in the additional supplemental testimony of Company witness Haynes and recommended by Public Staff witness Floyd, was appropriate to be included in the Company's base rates, subject to any adjustment based on the outcome of the Company's ongoing 2019 Fuel Factor proceeding. The Stipulating Parties also agreed that decrement Rider A1, equal to (0.375¢/kWh) on a jurisdictional basis, is appropriate to become effective on November 1, 2019.

Discussion and Conclusions

Based on all the evidence in this proceeding, the Commission finds and concludes that the stipulated jurisdictional average base fuel factor of 2.092¢/kWh, including the regulatory fee, is just and reasonable for DENC and ratepayers in this case. Further, the jurisdictional average base fuel factor should be differentiated between customer classes on a voltage basis, as provided on Company Additional Supplemental Exhibit PBH-1, Schedule 1, Page 2.

Finally, the Commission notes that no party opposed the Company's proposed Marketer Percentage. Based on all of the evidence in this proceeding, the Commission finds and concludes that effective February 1, 2020 a Marketer Percentage of 71%, should be applied to appropriately determine the fuel cost component of energy purchased for which the fuel cost is unknown, and shall remain in effect until approval of a new Marketer Percentage in the Company's 2021 fuel factor filing, or next general rate case, whichever is earlier.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 35-39

The evidence supporting these findings of fact and conclusions is found in the verified Application and exhibits, the Public Staff Stipulation, and the testimony of Company witnesses Miller and Haynes, Public Staff witness Floyd, Nucor witnesses Thomas and Wielgus, CIGFUR witness Phillips, and the entire record in this proceeding.

Summary of the Evidence

The Company's Application, as supported by Company witnesses Miller and Haynes, used the Summer/Winter Peak and Average (SWPA) cost of service methodology to allocate production and transmission plant costs for both the North Carolina jurisdiction and the North Carolina retail customer classes. The SWPA method recognizes two components of providing service to customers – peak demand and average demand – when determining the responsibility for costs of production and transmission plant and related expenses. The peak demand component takes into account the hour when the load on the system is highest during both the summer months and the winter months. The average demand component recognizes that there is a load incurred by the system over the course of all hours during the year. The average demand is determined based upon the total energy provided to the customers during the year divided by the total number of hours in the year. The average component is then weighted by the system load factor, and the peak component is weighted by 1 minus the system load factor. The load factor is calculated by taking the Company's actually experienced average demand divided by its actually experienced peak demand during the test year.

Witness Miller explained that DENC developed and presented in its Form E-1, Item 45, the "per books," annualized, and "fully-adjusted" jurisdictional and customer class cost of service studies for the test year ended December 31, 2018. Witness Haynes explained that in developing the SWPA cost of service study (COSS), the Company also made two adjustments in the course of calculating the SWPA allocation factors. The first is an adjustment to the Company's recorded summer and winter peaks to recognize and add back the kW generated by NUGs interconnected to DENC's distribution system that are not included in those values. Witness Haynes testified that this adjustment was approved by the Commission in the Company's 2016 Rate Case. The second is an adjustment to remove the demand and energy requirements of three customers, one wholesale customer, NCEMC, and two large industrial customers in the Company's Virginia jurisdiction, for whom the obligation to provide generation service has ended or will end during 2019. Tr. vol. 4, 374.

Witness Miller testified that the objective of jurisdictional and customer class cost of service studies is to determine the allocation of a share of the system's revenues, expenses, and plant related to providing service across multiple jurisdictions. Certain items can be assigned directly to the jurisdiction and classes based on the utility's records, but other items are not directly assignable and must be allocated. Witness Miller stated that in this proceeding, the Company allocated its production and transmission plant and expenses using the SWPA cost of service methodology. He noted that the Commission has approved DENC's use of the SWPA method in DENC's last six general rate cases, dating back to 1983, including the 2016 Rate Case. Witness Haynes testified that the SWPA allocation method is consistent with the manner in which DENC plans and operates its system. Specifically, the "Summer and Winter" peak component recognizes the total level of generation resources necessary to serve the system peaks, while the average component recognizes the type of generation serving customers' energy needs year-round. *Id.* at 371-73, 502-10.

Witness Haynes also emphasized that use of a single peak or other peak-only methodology could allow certain customer classes that have zero demand during the peak hour(s) of the year to fully avoid responsibility for production plant costs. Witness Haynes explained that a common example is streetlights that normally do not operate during peak hours. Witness Haynes also highlighted the NS Class as another example unique to DENC's North Carolina jurisdictional load. Witness Haynes explained that Nucor, the only customer in the NS Class, has an average annual demand throughout the year of approximately 106 MW, while Nucor's average of its summer (July 2, 2018) and winter (January 7, 2018) coincident peak demands is approximately 42 MW. Witness Haynes explained that without recognizing an average component in the cost allocation, this customer class would "pay" for only 42 MW and escape cost responsibility for an average of 64 MW for the rest of the year (i.e., the average demand of 106 MW less the allocated demand of 42 MW). Witness Haynes explained that by recognizing both the energy needed to serve load at the peak hour, as well as energy consumed throughout the year, the SWPA method allocates some portion of these system costs to all customers, including those customers that can reduce their peak demand and those that may not place a demand on the system during the respective summer and winter peak hours. Such customers still use and receive the benefit of the Company's investments in production assets by paying lower energy costs, specifically fuel costs, during all other hours. *Id.* at 371-74.

Public Staff witness Floyd agreed with the Company's use of the SWPA cost of service methodology in this proceeding because it appropriately allocates the Company's production plant costs in a way that most accurately reflects the Company's generation planning and operation. He testified that unlike other methodologies that allocate all of the production plant costs based on a single coincident peak or on a series of monthly peaks, the SWPA methodology recognizes that a portion of plant costs, particularly for base load generation, is incurred to meet annual energy requirements throughout the year and not solely to meet peak demand at a particular time. Witness Floyd also stated that the Public Staff agrees with DENC's proposed adjustments to the COSS as appropriately recognizing the impact of distribution connected NUGs and the removal of wholesale contract load in 2020 on DENC's utility system. Tr. vol. 6, 68-72.

CIGFUR witness Phillips testified that the SWPA method is inconsistent with both DENC's method of planning for future capacity requirements, and the increase in the portion of its generating mix represented by natural gas, as outlined in its 2018 IRP. Witness Phillips also claimed that the SWPA method over-allocates cost to large, high load factor customers without a symmetrical fuel cost allocation. Witness Phillips advocated for the use of the Summer/Winter Coincident Peak (S/W CP) cost of service methodology as consistent with system planning and cost causation principles, arguing that the S/W CP corrects over-allocations of costs to large, energy intensive industrial customers, such as those on the Company's Schedule 6VP. *Id.* at 422-25.

Nucor witness Wielgus did not recommend that the 1-Coincident Peak (1-CP) methodology be used in the cost of service study in this proceeding, but he did recommend that the Commission examine in a formal proceeding whether using a 1-CP or 5-CP method instead of the Company's proposed SWPA would be most appropriate for DENC given the way that PJM uses coincident peaks and that Duke Energy conducts its cost of service studies for its North Carolina jurisdiction. Witness Wielgus argued that the SWPA fails to properly recognize the system's need for generation and is not consistent with the Company's primary need for generation capacity, which is to serve its annual peak demand. Witness Wielgus also argued that the SWPA method fails to recognize the system benefits associated with the NS Class. In particular, witness Wielgus noted that Nucor's facility comprises approximately 20% of the Company's load, has a high load factor that is beneficial to the Company's system operations and corresponding costs, and the service to Nucor is not firm and Nucor must curtail if called upon to do so. Witness Wielgus calculated a value of the capacity that is avoided when Nucor is curtailed based on its peak load of 172 MW and its load during the summer and winter peak hours of 42 MW and claimed that if Nucor were a firm customer, the Company would have to secure an additional 129 MW of capacity every day of the year at an annual cost of $5.7 million. *Id.* at 378-400.

Nucor witness Thomas presented two variations on the allocation of production costs using a 1-CP model and a re-weighted Summer/Winter Peak and Average (reweighted SWPA) model. Witness Thomas explained that for the 1-CP model he replaced the SWPA allocator with the single highest coincident peak demand, which in this proceeding was the winter peak demand net of North Anna. In the reweighted SWPA, witness Thomas explained that he used a 60% weight for the summer/winter peak demand component and a 40% weight for the average demand (energy) component. Witness Thomas concluded that under the 1-CP scenario, Nucor would have a relative rate of return (ROR) index before the revenue increase of 3.10, which is significantly higher than the 0.84 index computed by the Company under its SWPA scenario. In the reweighted SWPA, Nucor has a relative ROR of 1.20 before the revenue increase. Finally, he explained that to achieve a ROR index of 0.80 for Schedule NS, as the Company's SWPA methodology does, Nucor's base revenue would have to decrease by nearly $10.5 million under the 1-CP scenario and $2 million under the reweighted SWPA scenario. *Id.* at 404-08.

Company witness Haynes extensively addressed and rebutted the cost of service arguments of witness Phillips on behalf of CIGFUR and witness Wielgus on behalf of Nucor in his rebuttal testimony. Witness Haynes explained that the SWPA method reasonably and appropriately recognizes the two components of providing service to customers, peak demand and average demand, and is consistent with the manner in which the Company's planning department plans for and meets DENC's system needs, taking into consideration the need both to meet peak demands and to provide resources that can be operated to serve customers throughout the year. The Company's SWPA cost of service study followed the same approach for Schedule NS (as well as all other classes) used in the cost of service studies filed and approved in DENC's three most recent rate cases, Docket No. E-22, Sub 532 in 2016, Sub 479 in 2012, and Sub 459 in 2010. Specifically, as described by Company witness Haynes, the Company used both a summer and winter peak demand for the NS Class that reflected Nucor's measured demand and recognized the interruptible nature of Nucor's arc furnace pursuant to the confidential terms and conditions of the Company's contract with Nucor. The 42 MW of peak demand assigned to the NS Class represents the average of the winter and summer peaks of the NS Class at the time of the test year system winter and summer peaks. These peak demands were used to develop the production plant and transmission related demand allocation factors.

Witness Haynes explained that the "Summer and Winter" peak component recognizes the total level of generation resources necessary to serve the system peaks, while the average component recognizes the dispatch of different types of generation providing the system with low cost energy year-round. Witness Haynes pointed to the Company's recent addition of the 1,588 MW Greensville County CC, as well as the Company's historical investments in its baseload fleet as production-related plant operated throughout the year to provide baseload energy to the Company's customers. Witness Haynes also specifically pointed to the Company's investment in nuclear plant at the end of 2018 that represented approximately 26% of the total production plant invested. He also reiterated the Commission's consistent support for the Company's continued use of the SWPA methodology as the proper method to assign production plant costs to all customer classes, including the Schedule NS Class. Tr. vol. 4, 436-47.

Witness Haynes testified that the S/W CP methodology advocated by CIGFUR witness Phillips is not reasonable or appropriate for DENC because its reliance on only the two hours of DENC's summer and winter peaks is inconsistent with the way DENC plans and operates its system to meet the system peaks and deliver low cost energy throughout the year. He also explained that use of the S/W CP would result in a significant shift of costs to the residential class. *Id.* at 437-38.

Witness Haynes also testified that witness Wielgus' recommendation that the Commission examine in a formal proceeding whether using a 1-CP or 5-CP method instead of the SWPA would be most appropriate for DENC is misplaced. Witness Haynes argued that such a method would increase the total North Carolina jurisdictional revenue requirement and significantly shift costs to the residential class while benefitting Nucor and the LGS and 6VP classes. Witness Haynes testified that regardless of the methodology approved by the Commission for use by Duke Energy, it is appropriate for the Commission to consider the usage characteristics of customers and the generation system's planning and operation for each utility to determine an appropriate allocation method, rather than not uniformly applying a particular method to all utilities. *Id.* at 437-66.

With respect to witness Wielgus' recommended modifications to the weighting of the peak demand and average components in the SWPA method as proposed by the Company, witness Haynes stated that the modifications are not consistent with the way customers use the Company's production and transmission systems and would result in a shift in cost responsibility from Nucor and other non-residential classes to the residential class, resulting in a higher increase in rates for residential customers than proposed by the Company. *Id.*

Witness Haynes also responded to witness Wielgus' claims regarding the benefits provided by Nucor to the Company's system, stating that the service arrangement with Nucor only requires a partial curtailment of its furnace load but not its total load and the Company is restricted in the number of hours such load can be curtailed. He noted that while Nucor's load factor may be considered higher than load factors for residential and small general service classes, it is not in the range of higher load factor customers in the LGS class. Witness Haynes also performed analyses of the value of Nucor's avoided capacity to the Company, concluding that while there was considerable value of curtailment to be considered in setting rates, the value was not as high as calculated by witness Wielgus. Witness Haynes also analyzed the benefit to the North Carolina jurisdiction and Nucor of recognizing Nucor's actually-curtailed peak load under the SWPA method. He concluded that recognizing Nucor's curtailed demand in developing the allocation methodology provides a significant and properly recognized financial benefit to Nucor, as well as a lower overall allocation of system costs to the North Carolina jurisdiction. He explained that the Company's SWPA allocation factors were calculated in a reasonable manner – consistent with the principles approved in DENC's 2016 Rate Case – that appropriately recognizes the value of Nucor's interruptibility to the system and does not overstate cost or understate returns for the North Carolina jurisdiction and its customer classes. *Id.*

In the Public Staff Stipulation, the Stipulating Parties agreed that the Company's SWPA methodology calculated using the system load factor to weight the average component and (1 – system load factor) to weight the peak demand component is appropriate for use in allocating the Company's per books cost of service to the North Carolina jurisdiction and between the customer classes in this case. The Public Staff

Stipulation also agreed to the two adjustments made in the course of calculating the SWPA as described above.

The CIGFUR Stipulation states that, for purposes of settlement only, the parties agreed that the Company's SWPA methodology, calculated using the system load factor to weight the average component and (1 – system load factor) to weight the peak demand component is appropriate for use in allocating the Company's per books cost of service to the North Carolina jurisdiction and between customer classes in this case. The CIGFUR Stipulation also provides that the parties agree to the two adjustments the Company made in the course of calculating the SWPA. The parties did not reach a compromise on the total base revenue increases the Company proposed to assign to the LGS and 6VP customer classes or the Company's proposed rates of return for the customer classes. The parties agreed that in the next general rate case, the Company would file the results of a class cost of service study with production and transmission costs allocated on the basis of the Summer/Winter Coincident Peak method in addition to the SWPA used in this proceeding and consider such results for the sole purpose of apportionment of the change in revenue to the customer classes. They also agreed that considering that no customers have taken service under the pilot RTP rates filed by the Company and approved by the Commission in Sub 532, the Company will work with CIGFUR to consider whether certain provisions within those rates should be modified. If there is mutual agreement between CIGFUR and DENC to such modifications, and CIGFUR indicates that at least one of its member customers is willing to take service under such rates, DENC agrees to re-file such rates with the Commission for approval with the modifications agreed upon within 60 days of such agreement.

At the hearing, on redirect examination witness Haynes testified that under the alternative cost allocation methodologies proposed by Nucor and CIGFUR, Nucor would receive a rate decrease, and the residential class would receive rate increases ranging from approximately $20 million to $63 million, as compared to the $17 million increase provided in the Company's supplemental filing. Tr. vol. 5, 48-50.

Discussion and Conclusions

The Commission finds and concludes that DENC has carried its burden of proof to show that the Company's SWPA methodology is the most appropriate cost of service methodology to use in this proceeding to assign cost responsibility for production plant to the North Carolina jurisdiction and the Company's customer classes. On this issue, the Commission gives substantial weight to the testimony of Company witnesses Haynes and Miller and Public Staff witness Floyd, and both Stipulations. The cost of service methodology employed in establishing an electric utility's general rates should be the one that best determines the cost causation responsibility of the jurisdiction and various customer classes within the jurisdiction based on the unique characteristics of each class' peak demands and overall energy consumption. Witness Haynes testified extensively that the Company's investments in generating plant, including the recently placed in service Greensville CC, are designed to meet the Company's system peaks and to deliver low cost energy throughout the year. Witness Haynes explained that the SWPA methodology appropriately recognizes that DENC's system planning is designed to meet both the Company's peak and average system demands and energy needs of customers throughout the year. Both Company witnesses Haynes and Miller and Public Staff witness Floyd testified that the SWPA method appropriately matches allocation of production plant with DENC's generation planning and operations. The Commission finds that, for purposes of this proceeding, the SWPA cost of service methodology properly recognizes the manner in which DENC plans and operates its generating plants to provide utility service to customers in North Carolina.

Based on the facts in this case, a methodology that does not properly consider the effect of overall energy consumption, but focuses mainly on peak responsibility, such as the 1-CP methodology, would not properly represent the way in which the Company plans for and provides its utility service and the way customers use that service. The Commission is not persuaded that either the S/W CP methodology or the 1-CP methodology is appropriate for the Company in this proceeding, nor does the Commission see the need to open a formal proceeding to investigate the implementation of a 1-CP or 5-CP methodology for DENC in future rate cases. The disparity between allocation factors for peak demand-related factors and energy-related factors is apparent for each methodology, with the SWPA resulting in the most equitable sharing of the rate of return among DENC's customer classes in this case. Because the Commission finds that the SWPA method is not unreasonable or flawed, the Commission does not find Nucor witness Wielgus' arguments as to the inappropriateness of the SWPA methodology proposed by the Company in this proceeding persuasive. The Commission also continues to find and conclude that cost allocation does not lend itself to a one size fits all approach, and the specific circumstances of each utility must be considered when determining the appropriate cost allocation methodology for that utility.

Based on the stipulations and the testimony, the Commission also finds that including the distribution-interconnected NUG generation in the average portion of the SWPA, but not including this NUG generation in the Company's recorded summer and winter peaks creates a mismatch between the peak and average components of the Company's SWPA COSS. The Commission concludes that the Company's adjustment to the summer and winter peaks to recognize the NUG generation at the distribution level appropriately recognizes the impact those NUGs have on DENC's utility system and is approved.

Based on the stipulations and the testimony, the Commission also finds that the adjustment to remove demand and energy requirements of three customers for whom the obligation to provide generation service has ended or will end in 2019 is appropriate.

Based on the evidence in this proceeding, including the stipulations, the Commission finds and concludes that the greater weight of the evidence shows that the SWPA cost of service methodology provides the most appropriate methodology to assign fixed production costs by incorporating DENC's seasonal peak demands at the two single hours they occur and by incorporating the total energy consumed by the jurisdiction and customer classes over all the other hours of the year. In addition, the Commission finds good cause to require that the Company should continue to file a cost of service study using the SWPA methodology annually with the Commission.

Moreover, as a result of the opposing testimony between the DENC and CIGFUR witnesses, the Commission finds and concludes that the CIGFUR Stipulation is the product of the give-and-take between the parties during their settlement negotiations in an effort to appropriately balance DENC's usage of the SWPA and CIGFUR's desire to investigate a different methodology for the sole purpose of apportionment of the change in revenue to the customer classes in the next general rate case. The Commission finds and concludes that the CIGFUR Stipulation was entered into by the parties after substantial discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute in this docket. As a result, the CIGFUR Stipulation is material evidence to be given appropriate weight in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 40

The evidence supporting this finding of fact and conclusions is found in the verified Application, the testimony of Company witness Haynes, Public Staff witness Floyd, CIGFUR witness Phillips, Nucor witness Wielgus, the Public Staff Stipulation, and the entire record in this proceeding.

Summary of the Evidence

The Application and testimony and exhibits of Company witness Haynes explain how DENC proposed to apportion the jurisdictional revenue requirement established using the Company's SWPA jurisdictional and class COSS among the customer classes. Witness Haynes' testimony and exhibits assigned the revenue requirement to specific rate schedules and then calculated the percent increase that customers on each rate schedule would experience.

In apportioning the revenue requirement among the customer classes, witness Haynes identified general and class-specific principles that the Company used to equitably distribute the base rate revenue increase, including: (1) all classes should share in the non-fuel base rate revenue increase in a manner that moves each class of customers closer to parity with the North Carolina jurisdictional ROR; (2) generally, if a customer class has a ROR index less than 1.00, such class should receive a percentage increase that is greater than the overall jurisdiction percentage base rate increase. If a customer class has a ROR index greater than 1.00, such class should receive a percentage increase that is less than or equal to the overall jurisdiction percentage base rate increase; (3) for classes outside of a reasonable return index range of 0.90 and 1.10 (Parity Index Range), an effort must be made to more reasonably align the rates customers pay with their responsibility for cost, even if the index achieved after apportionment still remains outside of the Parity Index Range; (4) for purposes of apportioning the increase for the LGS, 6VP, and NS classes, which include the Company's large non-residential customers, in addition to the class rates of return and resulting indices, consideration should also be given to the appropriate increase for these customer classes based upon certain non-cost factors that support a lesser increase for large industrial customers with high load factors; and (5) for purposes of apportioning the increase to the NS Class, the Company recognized the need to equitably address the unique nature of the Company's electric service arrangement with its largest and most energy-intensive customer, Nucor. Tr. vol. 4, 384-87.

Specific to the non-cost considerations that DENC took into account in apportioning the revenue increase among the industrial customer classes, witness Haynes testified that he considered the quantity and timing of large industrial manufacturing customers' electric usage in their industrial operations, as well as factory utilization and the economic vitality of the Company's North Carolina service territory, as it relates to these industrial customers. Witness Haynes presented a summary table of the Company's allocated rate base, class rate of returns, apportionment of the non-fuel base rate increase, and the class rates of return after apportionment. Witness Haynes further detailed the proposed apportionment by class and explained that while the Company's customers would experience an increase in non-fuel base rates, this increase would be substantially moderated after taking into account certain reductions, like that anticipated for the fuel component of rates. *Id.* at 378-95.

After explaining how the proposed non-fuel base revenue increase was apportioned across customer classes, witness Haynes discussed how the components of the rate schedules are adjusted to achieve the non-fuel base rate increases. Witness Haynes stated that the target percentage increase listed by class in his summary table is applied to the total present revenue to calculate the target revenue increase for the rate schedule. Further, witness Haynes explained, a factor is used to adjust each rate component and applied to the present rates to develop a proposed rate that would result in the proposed revenue requirement. Witness Haynes noted that this information is included in Columns (7) through (14) of the Company's Form E-1 Item 42a summary sheet. Finally, witness Haynes noted that the rate design method used in this proceeding generally produced a proposed customer charge less than the fully-supported customer charges presented by witness Miller. *Id.* at 395-97.

In his testimony, Public Staff witness Floyd disagreed with the Company using only the base non-fuel revenue to calculate class rate of returns and instead recommended that DENC use both base fuel and base non-fuel revenues to determine base revenue assignment. Witness Floyd testified that, consistent with past rate cases, several principles should be taken into account when apportioning any combined base fuel and base non-fuel revenues among the various classes, all of which attempt to assign the revenue requirement to each customer class in an equitable and fair manner and to minimize rate shock to any individual class. Finally, witness Floyd explained that because the Public Staff recommended a total revenue decrease, all of the traditional principles the Public Staff rely on in apportioning the revenue requirement are not necessarily applicable. Witness Floyd testified that it is still appropriate to focus on addressing any disparities in the class rate of returns when apportioning the decrease, but any individual customer class revenue decrease should be limited so that no individual customer class sees an increase in its assigned revenue requirement. Tr. vol. 6, 72-77.

In his testimony, Nucor witness Wielgus disagreed with witness Haynes' rate design as it relates to Nucor and the proposed 0.80 rate of return index for the Schedule NS class. Witness Wielgus recommended that the percentage increase in base rates to Schedule NS should not exceed the average of the percentage increases applied to rate schedules in the LGS and 6VP classes. *Id.* at 393-96.

In his testimony, CIGFUR witness Phillips noted that the Company's proposed distribution of the revenue increase moves the rate of return for the 6VP and the LGS classes closer to cost and the system average rate of return. Witness Phillips recommended that because the Company's proposed method of distributing the requested increase to classes moves rates closer to cost in a meaningful manner, it should be implemented as proposed. *Id.* at 417-22.

In his rebuttal testimony, witness Haynes noted that witness Phillips' comment that the 6VP class has been providing "excess returns" to DENC, and pointed out that the same is true for the LGS class and that both classes are important to the Company's North Carolina service territory, with rate of return indices well above the Parity Index Range at 1.33 for the LGS class and 1.22 for the 6VP class. Witness Haynes explained that the Company considered the nature of these customers' usage, as well as concerns about the economic competitiveness of industrial customers and the need to maintain the economic vitality of the Company's North Carolina service territory. He pointed out that in the 2016 Rate Case, the Company gained approval of Rate Schedule 6L to help large high load factor customers who may utilize their plant efficiently in multiple daily shifts. Tr. vol. 4, 481-83.

Witness Haynes also disagreed with witness Wielgus' recommendation that Schedule NS should not exceed the average of the percentage increase applied to rate schedules in the LGS and 6VP classes. He stated that the rate of return index for the LGS and 6VP classes is well above the Parity Index Range and, given other non-cost factors, these two large industrial classes should receive a very low percentage increase. Witness Haynes further noted that the Company modified its position on the apportionment of the revenue increase to Schedule NS and that the Company believes that the Schedule NS class should have a lower rate of return index. Specifically, witness Haynes stated that in the 2016 Rate Case, the Schedule NS class' rate of return index moved from 0.43 to 0.74, which represented a move of two-thirds of the way toward the low end (90% of jurisdictional rate of return) of the Parity Index Range, and he noted that prior to the 2016 Rate Case based upon the stipulation and the Commission's order and Finding of Fact No. 42, this class received a non-fuel base rate increase that moved its ROR index from 0.43 to 0.75. This moved the NS class two-thirds of the way toward the low end (90% of jurisdictional ROR) of the Parity Index Range. Prior to the 2016 Rate Case, a deficiency had existed for a number of years, as reported in the Company's past rate cases and annual jurisdictional cost of service studies filed with the Commission. Witness Haynes stated that he discussed the Company's service agreement with Nucor and provided some reasonable calculations of the value of this agreement in his Rebuttal Schedule 2. In Rebuttal Schedule 3, he provided an analysis showing how the North Carolina jurisdiction is benefitting from the Company and Nucor having this service arrangement.

Further, witness Haynes noted that earlier in his direct testimony filed on March 29, 2019, he proposed moving the Schedule NS class to a ROR index of 0.80. In the Company's supplemental filing, Schedule NS had a ROR Index of 0.79. Now, considering this operational benefit to the system and the benefit in cost allocation to the North Carolina jurisdiction because of the partially interruptible nature of service to Nucor, witness Haynes stated that he believes it is appropriate to target an ROR index of 0.75 for the Schedule NS class. He stated that this is a very important large industrial customer, and he believes that this reduction in the recommended ROR index is reasonable. *Id.* at 479-84.

In his Stipulation testimony, witness Haynes testified that Section VI[10] of the Public Staff Stipulation presents a just and reasonable approach to establishing the Company's North Carolina jurisdictional cost of service and class cost of service for the allocation of production and transmission plant costs and related expenses based on the SWPA allocation methodology. *Id.* at 486-88.

As contemplated by Section III.D of the CIGFUR Stipulation, counsel for CIGFUR cross-examined Company witness Haynes on the rate of return index provided for the LGS and 6VP classes under the Public Staff Stipulation. Witness Haynes agreed that these classes will be paying rates above cost and beyond the range of reasonableness but agreed with CIGFUR counsel that the increases for these classes are very small. He also pointed out that the terms of the Public Staff Stipulation result in a reduction in the increase in base non-fuel revenue from these classes from the Company's initial request. Tr. vol. 5, 40-43.

The Nucor Steel-Hertford brief states that through the testimony filed in this case, the Commission has been presented with reasoning justifying an ROR index for the NS class at either 0.70 or 0.75 only.[11] According to the Nucor brief, there is no reasoning on record (other than that contained in DENC's direct testimony which is superseded by DENC's Haynes rebuttal testimony advocating for 0.75) that supports an ROR index for Schedule NS/Nucor any higher than 0.75. Further, the brief states that simply put, there is no substantial record evidence supporting an ROR index of 0.80 for Schedule NS/Nucor.

Discussion and Conclusions

Based on the Public Staff Stipulation and the evidence in the record, the Commission concludes that for purposes of this proceeding it is appropriate to apportion the proposed base fuel and non-fuel revenue increase approved in this Order using the methodology recommended by DENC as consistent with the Public Staff Stipulation. In reaching this conclusion, the Commission gives substantial weight to the Public Staff Stipulation and the full record of testimony supporting the Stipulation. In support of the

[10] At the hearing, witness Haynes corrected this statement in his testimony, which had referenced Section V of the Public Staff Stipulation. Tr. vol. 4, at 362.

[11] *See, e.g.*, Direct Testimony of Paul J. Wielgus at 17-19; Rebuttal Testimony of Paul B. Haynes at 45, lines 5-13, and 50, lines 2-10.

Stipulation, witness Haynes states that while other Company witnesses support the reasonableness of the stipulated non-fuel base revenue increase, he believes the Stipulation in Section V Cost Allocation, Rate Design, and Terms and Conditions, Paragraph A presents a just and reasonable approach to establishing the Company's North Carolina jurisdictional cost of service and class cost of service. He explained that this approach includes the allocation of production and transmission plant costs and related expenses based upon the SWPA allocation methodology calculated using the system load factor to weight the average component and (1 – system load factor) to weight the peak demand component. Tr. vol. 4, 486-87.

Further, witness Haynes stated that the Public Staff Stipulation addresses the apportionment of the revenue requirement and the design of rates in Section V, Paragraph B. With regard to these matters, the Stipulation provides the following according to witness Haynes:

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

2. The Stipulating Parties agree that the Company shall implement the rate design proposed by Company witness Haynes within his direct testimony, filed contemporaneously with the Company's Application in this docket as adjusted by this Stipulation.

3. The Stipulating Parties agree that all classes should share in the base case revenue increase.

4. In meeting the provisions of 1, 2, and 3 in apportioning the approved revenue requirement to the customer classes, awareness and consideration is given to the rate of return indexes for the LGS and 6VP classes being above 1.20 and an appropriate rate of return index for the Schedule NS class.

Witness Haynes stated that he considers these provisions of Section V, Paragraph B to be reasonable for the purpose of establishing rates in this proceeding. *Id.* at 487-88.

Finally, based on the entire record in this proceeding, the Commission is persuaded that the Company has treated the NS Class and Nucor appropriately in its cost of service study and that no additional recognition of the benefits associated with the Nucor contract should be made in this proceeding. The facts and evidence in this proceeding show that the Company has consistently followed the same approach in this case of recognizing the benefits of Nucor's interruptibility – to both Nucor and the North Carolina jurisdiction – consistent with DENC's approach in the Company's past three rate case proceedings. Further, the curtailment provisions in the Nucor agreement have not been modified since last reviewed by the Commission in 2016. Nucor's contract with the

Company provides Nucor with flexibility in deciding how and when it consumes energy for the vast majority of hours in the year and the Company's treatment of Nucor through its SWPA methodology is reasonable and appropriate.

Based on the evidence presented, the Commission concludes that the rate of return indices for all of the classes are reasonable and should be accepted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 41-43

The evidence supporting these findings of fact and conclusions is found in the Company's Form E-1, the direct testimony of Company witnesses Haynes and Mitchell, the testimony of Public Staff witness Tommy Williamson, the Public Staff Stipulation, and the entire record in this proceeding.

Summary of the Evidence

Changes to service regulations

In his direct testimony, Company witness Haynes testified that Item 39 of the Company's Form E-1 shows the Company's proposed changes to each section of the terms and conditions of service, also known as the Company's service regulations. Specifically, he referenced the proposed changes to several miscellaneous service fees to cover the updated cost of service, excess facilities charge percentages, and minor wording changes. Witness Haynes stated that each change is accompanied by comments that provide a description of the relevant proposed change. He also testified that the Company proposed to wait to implement these changes until permanent rates become effective and the changes are approved by the Commission. Finally, witness Haynes confirmed that the non-fuel base rate revenue increase includes the Company's proposed changes to the miscellaneous charges. Tr. vol. 6, 383, 408-09.

No other party testified in opposition to the Company's proposed changes to the terms and conditions, and witness Haynes was not cross examined on this issue at the hearing.

Vegetation management

Public Staff witness Tommy Williamson described DENC's Vegetation Management Plan (VMP). He stated that there have been no significant changes in the VMP since April 2014, when it was filed by DENC in Docket No. E-22, Sub 491. Witness Williamson testified that DENC has approximately 4,160 miles of distribution right-of-way (ROW) that it maintains in North Carolina, and that the Company targets to trim approximately 800 miles annually. He further testified that the Company trims approximately 1,200 to 1,300 miles of transmission ROW annually, with about 200-300 miles of that work done in North Carolina. Finally, witness Williamson stated that DENC's VMP is reasonable in ensuring that all planned miles of trimming are done within the appropriate cycle.

Quality of service

Company witness Mitchell provided testimony regarding DENC's performance with regard to customer service. He testified that the Company's generating fleet has demonstrated excellent performance results. He also stated that DENC continues to provide excellent customer service, and that the Company has improved its North Carolina System Average Interruption Duration Index (SAIDI) performance, excluding major storms, by over 20% since 2007, and maintained consistent performance below 120 minutes since 2016. Witness Mitchell also testified that the Company continues to achieve excellence in customer service by offering innovative solutions in response to customer expectations, including leveraging technology to perform quick, seamless customer transactions. He noted that DENC customers completed more than 16 million online transactions during 2018 and that usage of online transactions has increased by 12% since 2017. He described the Company's promotion of social media interactions with customers, including its messages to educate customers on important issues such as energy conservation and service reliability. Witness Mitchell also testified about recognition for outstanding performance that the Company's parent, DEI, had received during the past several years. Tr. vol. 6, 169-70, 178-81.

Public Staff witness Tommy Williamson testified that the Public Staff had reviewed service-related complaints received by the Public Staff's Consumer Services Division, the Company's call center operation reports filed with the Commission, SAIDI performance, and System Average Interruption Frequency Index (SAIFI) statistics. Witness Williamson testified that the data for non-Major Event Days showed that the Company's SAIDI and SAIFI results have been stable and slightly improving. He also testified that the vast majority of inquiries made by DENC customers through the Public Staff's Consumer Services Division were requests to establish or modify payment arrangements, and that no other category of inquiry exceeded 4% of the total. Based on this information, witness Williamson found the overall quality of electric service provided by DENC to retail customers to be adequate. Tr. vol. 6, 466-67.

In Section IX of the Public Staff Stipulation, the Stipulating Parties agreed that the quality of DENC's service is good.

Conclusions

The Commission finds and concludes that the Company's proposed changes to its service regulations, as included in Item 39 of its Form E-1, are reasonable and appropriate, and should be approved.

In addition, the Commission finds and concludes that DENC's VMP performance is reasonable and should be accepted.

Further, the Commission finds and concludes that DENC's overall quality of service is good.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 44–46

The evidence supporting these findings of fact and conclusions is found in the testimony of Company witness Williams, the Company's 2015 Integrated Resource Plan, the testimony of Public Staff witness Lucas, and the Public Staff Stipulation.

Summary of Evidence

In his direct testimony Company witness Williams discussed DENC's strategy for complying with federal and state environmental regulations. Witness Williams testified that to comply with the CCR Rule[12] and the Environmental Protection Agency's (EPA's) effluent limitations guidelines (ELGs),[13] the Chesterfield Power Station (Chesterfield) underwent a number of wastewater and environmental improvements in 2017 to transition from wet sluicing coal ash to a dry ash management system. In order to manage the dry coal ash, DENC constructed an onsite, permitted landfill. Witness Williams stated that the onsite landfill has been receiving dry ash since 2017. Overall, witness Williams testified that the Company's actions to close its ash facilities have been reasonable and prudent. Tr. vol. 5, 90, 93.

Public Staff witness Lucas testified that in 2015 the Company began making investments at Chesterfield to comply with the CCR Rule and the ELGs. These investments are referred to by the Company as the Chesterfield Integrated Ash (CHIA) project. He explained that the CHIA project included wet to dry conversion of several units, among other things. Witness Lucas testified that in June 2015 the Company executed an agreement with a contractor to design and build dry ash handling facilities for Chesterfield Units 3, 4, 5, and 6, and that the total CHIA project cost was $124.2 million. Witness Lucas further testified that in its 2015 Integrated Resource Plan (IRP) the Company indicated that Units 3 and 4 would be retired in 2020. Witness Lucas testified that Chesterfield Units 3 and 4 were retired in March 2018. Witness Lucas testified that the Company should not have made this long-term investment in Units 3 and 4 if they were to remain in service for less than five years. As a result, he opined that the investment made to convert these two units to dry ash handling was not prudent, and he recommended a disallowance of $25.7 million on a system-wide basis.

Witness Lucas calculated the disallowance based on the total generating capacity of Chesterfield Units 3, 4, 5 and 6, 1,302 MW, in relation to the combined capacity of Units 3 and 4, which is 270 MW, or 20.7% of the total Chesterfield Units 3, 4, 5 and 6 capacity. Witness Lucas applied the 20.7% capacity ratio to the $124.2 million total cost of the CHIA project to arrive at the recommended disallowance of $25.7 million on a system-wide basis. Tr. vol. 6, 189-91.

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[12] Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities, 80 Fed. Reg. 21,301 (Apr. 17, 2015).

[13] Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 80 Fed. Reg. 67,837 (Nov. 3, 2015).

Witness Lucas also discussed the proceeding in which the Virginia State Corporation Commission (VSCC) addressed this issue.[14] In its Final Order issued on August 5, 2019, the VSCC concluded that the costs incurred by VEPCO for the CCR wet to dry conversions of Units 3 and 4 was not reasonable and prudent, and, therefore, the VSCC denied recovery of those costs. Final Order, at 6-9. However, on August 23, 2019, VEPCO filed a Limited Petition for Reconsideration, requesting that the VSCC review its denial of the conversion costs for Units 3 and 4. On August 26, 2019, the VSCC issued an Order Granting Reconsideration that accepted VEPCO's petition and suspended operation of the Final Order pending further action by the VSCC on the petition.

Finally, witness Lucas disagreed with DENC witness Williams' contention that the EPA's 2015 ELGs forced DENC to convert its coal plants to dry ash handling. Witness Lucas testified that in September 2017 the EPA postponed the earliest compliance date for the new effluent limitations and pretreatment standards for FGD wastewater and bottom ash transport water for two years, from November 1, 2018, to November 1, 2020.

In her testimony, Public Staff witness Johnson made an adjustment to remove the costs associated with the common plant related to Chesterfield Units 3 and 4 based on the recommendation of witness Lucas, resulting in an annual revenue requirement reduction of $124,000. Tr. vol. 6, 33; Johnson Exhibit 1, Schedule 1(a).

The Public Staff Stipulation, in Section VII.A, provides that the costs of the wet to dry conversion for Units 3 and 4 at Chesterfield should be included in the stipulated revenue requirement, pending resolution of the dispute in Virginia. Section VII.A further states that if the final resolution in Virginia results in such costs being removed from the Virginia Rider E revenue requirement, the Company will establish a regulatory liability for estimated amounts recovered from North Carolina customers associated with the project costs beginning November 1, 2019, and ending on the effective date of rates established in the Company's next general rate case, and that the amortization of the regulatory liability balance will be incorporated into the revenue requirement developed in the Company's next general rate case.

Discussion and Conclusions

The Commission concludes that the result proposed in Section VII.A of the Public Staff Stipulation is not acceptable. The Commission has the utmost respect for the VSCC and is confident that the VSCC will reach a reasoned decision on the Chesterfield Units 3 and 4 conversion costs. However, under the Act the Commission has the authority and obligation to set just and reasonable rates for DENC in North Carolina. The Commission concludes that it should not delegate any portion of its authority and obligation to the VSCC, which would be the direct result of approving Section VII.A of the Public Staff Stipulation. Consequently, the Commission declines to accept Section VII.A of the Public

[14] Final Order, *Petition of Virginia Electric and Power Company for Approval of a Rate Adjustment Clause, Designated Rider E, for the Recovery of Costs Incurred to Comply with State and Federal Environmental Regulations Pursuant to § 56-585.1 A 5 E of the Code of Virginia*, No. PUR-2018-00195 (Va. S.C.C. Aug. 5, 2019), *reh'g granted*, (Va. S.C.C. Aug. 26, 2019).

Staff Stipulation, and proceeds with making its own independent analysis of the prudence and reasonableness of the Chesterfield Units 3 and 4 CCR conversion costs.

Pursuant to N.C.G.S. § 62-134(c), the utility has the burden of proof to show that its proposed rates are just and reasonable. Further, N.C.G.S. § 62-65(a) requires that the Commission's orders be based on competent, material and substantial evidence.

Prudent is defined, in pertinent part, as "1. Wise in handling practical matters; exercising good judgment or common sense. 2. Careful in regard to one's own interests; provident." *American Heritage Dictionary* 1054 (Houghton Mifflin Co., 1978).

With respect to prudence and reasonableness, the Commission applies the following general standard:

> [W]hether management decisions were made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or reasonably should have been known at that time. . . . 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.

Order Granting Partial Increase in Rates and Charges, *Application by Carolina Power & Light Company for Authority to Adjust and Increase Its Rates and Charges*, No. E-2, Sub 537, at 14 (N.C.U.C. Aug. 5, 1988), *rev'd in part on other grounds and remanded*, *Utils. Comm'n v. Thornburg*, 325 N.C. 484, 385 S.E.2d 463 (1989) (Harris Order).

With regard to DENC's decisions on the Chesterfield wet to dry conversion project, the Commission finds that there are four dates that inform the analysis of "whether management decisions were made in a reasonable manner and at an appropriate time." The first date is 2009. In a 2009 study by Golder Associates entitled "Chesterfield Dry Ash System Installation," Golder advised VEPCO on design and cost analyses performed by Golder for a wet to dry ash handling system conversion at the Chesterfield plant. In a letter to VEPCO dated June 10, 2009, Golder stated:

> [D]ue to a recent catastrophic spill event in Tennessee and the changing political climate with regard to open ash ponds, Dominion has chosen to evaluate alternatives to the waste handling system at the Station should the lower ash pond be closed and no longer available to receive the ash slurry. Golder was asked to analyze possible ash conveyance system alternatives for transporting an estimated 550,000 tons of ash per year to the proposed Facility and to develop a budgetary cost estimate for the conversion.

. . .

> Based on a review of available Station information, two site visits and discussions with Dominion, Golder believes a conventional wet-dry ash conversion is practical for the Station.

DENC Late-Filed Exhibit 4 (Part 1) at 148 (filed September 23, 2019).

The 2009 Golder study and recommendation is material evidence because of the eventual timing of the 2015 decision to proceed with wet to dry conversion at Chesterfield, and the 2018 retirement of Units 3 and 4. Had DENC gone forward with the wet to dry conversion in 2009, as recommended by its consultant, then it would have benefited from several more years of using the dry handling system at Units 3 and 4, rather than using the system for less than two years.

The second important date is 2015, for two reasons. First, as Public Staff witness Lucas testified, in June 2015 the Company executed an agreement with a contractor to design and build dry ash handling facilities for Chesterfield Units 3, 4, 5, and 6. Second, on July 1, 2015, DENC filed its 2015 IRP in Docket No. E-100, Sub 141. In Section 3.1.4, under the sub-heading “Retirements,” DENC stated:

> [A]lso under evaluation are the retirements of Chesterfield Units 3 (98 MW) and 4 (163 MW), and Mecklenburg Units 1 (69 MW) and 2 (69 MW), all modeled for retirement in 2020 (Plans A, C and D). Appendix 3J lists the planned retirements included in the 2015 Plan.

DENC’s 2015 IRP at 35.

The third important date in the Commission’s analysis is 2017. DENC witness Williams testified that the CHIA project was completed in 2017, and the onsite landfill began receiving dry ash.

The fourth important date is 2018, the year that DENC retired Chesterfield Units 3 and 4.

The Commission concludes that the above dates and events are substantial evidence bearing on the question of what DENC knew, or should have known, when it made the decision to expend millions of dollars on a dry ash handling system for Chesterfield Units 3 and 4. In weighing this evidence, the Commission gives substantial weight to the fact that virtually simultaneously in June and July 2015 DENC signed a contract that included the conversion of Chesterfield Units 3 and 4 to dry ash handling while planning to retire Chesterfield Units 3 and 4 in 2020.

Further, the Commission gives substantial weight to DENC’s 2015 IRP. The IRPs are planning documents in which the electric utilities invest many hours of expert thought and time. They are also documents on which the electric utilities and the Commission depend heavily in meeting their obligations to ensure reliable service. The Commission concludes that DENC having stated in its 2015 IRP that it planned to retire Chesterfield

Units 3 and 4 in 2020, and having modeled its IRP on the basis of that planned retirement of Chesterfield Units 3 and 4 in 2020, DENC knew with reasonable certainty that it would retire Chesterfield Units 3 and 4 in 2020.

The Commission also gives substantial weight to the fact that the CHIA project was completed in 2017. The Commission notes that contracts for such major construction projects typically include a projected completion date, and although not necessarily absolute, the target date is generally relied upon by the contracting parties. Thus, it is a reasonable inference that DENC knew in 2015, or had a reasonable expectation, that the CHIA project would be completed sometime in 2017, and, therefore, Chesterfield Units 3 and 4 would use the dry ash handling equipment for only three years prior to their planned retirement in 2020.

Based on the substantial, material and competent evidence presented by DENC and the Public Staff, the Commission finds and concludes that DENC's decision to include Chesterfield Units 3 and 4 in the CHIA project was not reasonable and prudent. In 2015, when DENC entered into the contract for conversion from wet to dry handling, DENC knew with reasonable certainty that it would retire Chesterfield Units 3 and 4 in 2020. With that knowledge, it was not reasonable or prudent for DENC to spend millions of dollars on a wet to dry conversion for CCR handling at Chesterfield Units 3 and 4 in 2017. As a result, DENC's cost of converting Chesterfield Units 3 and 4 to dry ash handling should not be recovered from DENC's retail ratepayers.

The Commission accepts Public Staff witness Lucas's calculation of the disallowance of $25.7 million on a system-wide basis, and Public Staff witness Johnson's North Carolina retail adjustment resulting in an annual revenue requirement reduction of $124,000. Johnson Exhibit 1, Schedule 1(a). Further, the Commission finds good cause to require DENC to consult with the Public Staff and provide the Commission with confirmation that the Public Staff's recommended adjustment will result in the removal of all North Carolina retail jurisdictional costs and effects arising from the wet to dry CCR conversion project for Units 3 and 4 of the Chesterfield Power Station from DENC's revenue requirement and rate base.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 47-48

The evidence supporting these findings of fact and conclusions is found in the testimony and exhibits of the Company and the Public Staff, the testimony of CIGFUR witness Phillips, and in the Public Staff and CIGFUR Stipulations.

Pursuant to N.C.G.S. § 62-133(a), the Commission is required to set rates that are "fair both to the public utilities and to the consumer." In order to strike this balance between the utility and its customers, the Commission must consider, among other factors: (1) the utility's reasonable and prudent cost of property used and useful in providing adequate, safe and reliable service to ratepayers, and (2) a rate of return on the utility's rate base that is both fair to ratepayers and provides an opportunity for the utility through sound management to attract sufficient capital to maintain its financial strength. *See* N.C.G.S. § 62-133(b).

As fully discussed above, the provisions of the stipulations are the product of the give-and-take of settlement negotiations between DENC and the Public Staff, and between DENC and CIGFUR. In comparing the Public Staff Stipulation to the Company's Application and considering the direct testimony of the Public Staff's witnesses, the Commission notes that the Public Staff Stipulation results in numerous downward adjustments to the costs sought to be recovered by DENC. In addition, it is readily apparent from the terms of the Public Staff and CIGFUR Stipulations that the Stipulating Parties weighed their interests and negotiated to achieve the results most important to them, while also being willing to recognize the priorities of the other side in order to reach compromise. The result is that the stipulations strike a fair balance between the interests of DENC and its customers.

As discussed above, the Commission has fully evaluated the provisions of the stipulations and concludes, in the exercise of its independent judgment, that the provisions of the stipulations are just and reasonable to all parties to this proceeding in light of the evidence presented, and serve the public interest, with the exception of Section VII.A of the Public Staff Stipulation and subject to the qualifications and direction provided in Findings of Fact Nos. 60-62 and the discussion thereunder relating to the costs of removal portion of depreciation allowance. In particular, the provisions of the Stipulations appropriately balance the interests of DENC's customers in receiving safe, adequate, and reliable electric service at the lowest possible rates, and the interests of DENC in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the Commission concludes that the stipulations are just and reasonable under the requirements of the Act. Therefore, the Commission approves the Stipulations in their entirety, with the exception of Section VII.A of the Public Staff Stipulation and subject to the qualifications and direction provided in Findings of Fact Nos. 56-58 and the discussion thereunder relating to the costs of removal portion of depreciation allowance.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 49-52

The evidence supporting these findings and conclusions is contained in the Public Staff Stipulation, the Company's verified Application and Form E-1, DENC's Late-Filed Exhibits 3, 4, 5 and 6 filed on September 23, 2019, and the testimony and exhibits of the following expert witnesses: DENC witnesses Williams, McLeod, and Mitchell; and Public Staff witnesses Lucas and Maness.

The testimony and exhibits regarding DENC's CCR costs are voluminous. The Commission has carefully considered all of the evidence and the record as a whole. However, the Commission has not attempted to recount every statement of every witness. Rather, the following is a summary of the evidence that is in the record. Likewise, while the Commission has read and fully considered the parties' post-hearing briefs, it has not in this order attempted expressly to discuss every contention advanced or authority cited in the briefs.

Summary of the Evidence

Direct Testimony of Witnesses Mitchell and McLeod (DENC)

In his direct testimony Company witness Mitchell testified that DENC is requesting recovery of CCR compliance expenses incurred from July 1, 2016, through June 30, 2019. Tr. vol. 4, 176. The costs for that period are estimated to be $390.4 million. *Id.*

Company witness McLeod explained that the Company's proposed revenue requirement in this proceeding includes a recovery of expenditures made during the period of July 1, 2016, through June 30, 2019 in continued compliance with federal and state environmental regulations associated with managing CCRs and converting or closing waste ash management facilities at seven of DENC's generating stations. *Id.* at 27. As witness McLeod explained, pursuant to the 2016 DENC Rate Case Order the Company was permitted to recover CCR expenditures incurred through June 30, 2016, over a five-year amortization period and to defer subsequent costs to be evaluated for recovery in future rate cases.[15] In his supplemental testimony witness McLeod updated the amount of CCR costs sought for recovery during the period of July 1, 2016, through June 30, 2019, to reflect actual cash expenditures and the associated financing costs. *Id.* at 313. The Company is proposing to recover $377 million in system-level asset retirement obligation activities. Of this total the Company is seeking recovery of $21.8 million from the North Carolina retail jurisdiction.[16] Tr. vol. 6, p. 686. The Company originally proposed to recover these expenses over a three-year amortization period, tr. vol. 4, 27, but modified that proposal to a five-year amortization period, consistent with the Commission's treatment of similar deferred CCR costs in the recent DEP and DEC rate cases. Tr. vol. 6, 687. Witness McLeod explained that the unamortized CCR regulatory asset balance is included in the working capital section of rate base, which provides for recovery of financing costs associated with investor-supplied funds until they are recovered from customers. *Id.*

Direct Testimony of Witness Williams (DENC)

Witness Williams described the federal and state regulatory requirements that drove the CCR expenditures incurred from July 1, 2016, through June 30, 2019. Witness Williams explained that, as the Director, Environmental Services for Dominion Energy, it was his responsibility to oversee the corporate waste, water and biology programs.

[15] 2016 DENC Rate Case Order at 63, 149.

[16] The $21.8 million consists of the North Carolina jurisdictional portion of $376.7 million, $19.2 million, plus financing costs of $2.7 million that were incurred from the period of July 1, 2016, through June 30, 2019. *See* Maness Supplemental Exhibit 1, Schedule 1.

Tr. vol. 5, 77. He testified that his responsibilities included providing environmental support and leadership to the CCR closure projects. *Id.* at 94.

Witness Williams described his education and experience. He testified that he was a licensed Professional Geologist and earned a Bachelor of Science degree in geology from Radford University in 2001. Prior to joining Dominion Energy, witness Williams worked as an environmental manager at Waste Management Inc., North America's largest waste company, where he was responsible for environmental permitting and compliance for thirteen landfills located in Virginia, Maryland, Delaware, and West Virginia as well as over thirty trucking and transfer facilities located throughout the mid-Atlantic. Witness Williams was employed by the United States Navy, where he was responsible for the management and oversight of all east coast Marine Corps environmental remediation projects, including coal ash landfills, debris landfills, and many petroleum or chemical release sites. Witness Williams was also employed by the Virginia Department of Environmental Quality (VA DEQ), where he served as the solid waste permitting coordinator responsible for establishing the permitting standards for landfills, including ash and other industrial landfills. In his role with VA DEQ, witness Williams also led VA DEQ's revision of the Virginia coal combustion byproduct regulations, which governed the use of coal ash as structural fill before EPA's issuance of the CCR Rule. *Id.* at 94-95.

Witness Williams explained that DENC's CCR costs are attributable to eight Company generating facilities that are subject to new requirements for the closure of CCR surface impoundments, or ponds, and the continued operation of CCR landfills under federal and state regulations. Those facilities are: Bremo Power Station (Bremo), Chesapeake Power Station (Chesapeake), Chesterfield Power Station (Chesterfield), Clover Power Station (Clover), Mount Storm Power Station (Mt. Storm), Possum Point Power Station (Possum Point), Virginia City Hybrid Energy Center (Virginia City), and Yorktown Power Station (Yorktown). According to witness Williams, the coal ash stored at these facilities is the byproduct of decades of efficient and reliable energy generation for the Company's customers. Tr. vol. 5, 78-80.

Witness Williams testified that the Company is required to close its CCR ponds, and, eventually, when they cease receiving waste ash, its CCR landfills at these eight sites because of the CCR Rule that was published by the U. S. Environmental Protection Agency (EPA) on April 17, 2015. The CCR Rule finalized national regulations that provided a comprehensive set of requirements for the disposal of CCR from coal-fired power plants. The CCR Rule established technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act (RCRA). These regulations address location restrictions, operating and design criteria (including dam safety and stability), closure and post-closure care, and groundwater monitoring and corrective action requirements for CCR surface impoundments. The CCR Rule also sets out recordkeeping and public reporting requirements. *Id.* at 79.

Witness Williams testified that under the CCR Rule the Company had two options for closing its CCR surface impoundments: (1) closure in place, or (2) excavation and removal. For closure in place, the ash basin would be dewatered and then capped with an impervious cover. For closure by removal, the ash basin would be dewatered, then the ash would be excavated and placed in a lined, permitted CCR landfill. The CCR Rule also allowed excavated CCR to be beneficially reused under certain conditions. *Id.* at 80.

Witness Williams also described additional changes to federal regulations that impacted DENC's coal-fired facilities. On September 30, 2015, EPA finalized the Effluent Limitation Guidelines (ELG) rules revising the regulations for the Steam Electric Power Generating category. 40 C.F.R. Part 423. According to witness Williams, the rule set new federal limits on multiple metals found in wastewater that may be discharged from power stations including a prohibition on discharges associated with bottom ash management systems. Tr. vol. 5, 80*.*

Witness Williams testified that to meet the requirements of the CCR Rule the Company developed closure plans for each of its CCR ponds and landfills.[17] Witness Williams explained that the Company's original closure plans for its CCR surface impoundments, which were located at Bremo, Chesapeake, Chesterfield, and Possum Point, ultimately called for closure in place. The Company's original closure plans for those facilities remained effective until March 2019, when the Governor of Virginia signed into law Senate Bill 1355 (SB 1355). Senate Bill 1355 mandated that the Company excavate its CCR impoundments located in the Chesapeake Bay watershed, which include the ash basins at Bremo, Chesapeake, Chesterfield, and Possum Point. Excavated ash must be beneficially reused or placed in lined landfills located onsite or offsite. DENC will also be required to recycle or beneficiate approximately 25% of the excavated CCR, if it is determined through additional studies to be economically feasible. Witness Williams explained that Virginia's new excavation requirement is consistent with actions other states and utilities are taking in North Carolina, South Carolina, Georgia, and Alabama. *Id.* at 81-83.

Witness Williams clarified that SB 1355 has not affected the costs that are the subject of this proceeding, but when compared to closing all ponds in place the Virginia legislation requirements will result in an increase of the cost of closure. He further testified that the Virginia closure requirements allow multiple options for removal to onsite or offsite landfills as well as establishing a reasonable recycling target to limit that increase. He opined that closure in place comes with the uncertainty of future operations and maintenance, including corrective action for groundwater, and that the Virginia legislation removes this uncertainty by establishing excavation of basins and placement of the ash in a lined solid waste landfill as the only closure method. *Id.* at 93.

Witness Williams testified that DENC has historically managed CCR consistently with evolving industry standards and regulatory requirements. He stated that over time the utility industry and DENC have primarily used two types of disposal methods for managing CCR: surface impoundments for sluiced CCR and landfills for dry CCR. Witness Williams stated that as of 1988, 80% of CCR generated by the utility industry

[17] As required by the CCR Rule, DENC published its closure plans on its public website: www.dominionenergy.com/ccr.

was stored in surface impoundments or landfills. He stated that DENC has also sought opportunities to find beneficial uses for CCR, including use as an ingredient in concrete and dry wall. Witness Williams stated that by 2012, 40% of the CCR being generated was beneficially reused while the remaining 60% was being stored in CCR impoundments and landfills. Since the 1990s, DENC has recycled an annual average of 500,000 tons of CCR for beneficial reuse in the concrete and drywall industries. *Id.* at 84-85.

Witness Williams provided an historical summary of CCR management at each of the Company's eight coal-fired facilities and further described the CCR Rule compliance activities that occurred from July 1, 2016, through June 30, 2019, for which DENC is seeking recovery in this case. He further testified that the Company's actions to comply with the federal and state requirements have been reasonable and prudent. Tr. vol. 5, 93. According to witness Williams, no witness in this case has challenged or recommended disallowances related to the Company's strategy and activities described below to comply with the CCR Rule. *Id.* at 165. The following is a summary of the history of DENC's electric generating plants provided by witness Williams.

Bremo

Bremo was commissioned in 1931 as a coal-fired power station. CCR management consisted of sluicing wet fly and bottom ash to three onsite ash ponds — the East, West, and North ponds. The East Ash Pond (EAP) was constructed in multiple stages, beginning in the 1930s. *Id.* at 86. The EAP stopped receiving CCR in the mid-1980s and became inactive thereafter. *Id.* at 118-19. The West Ash Pond (WAP) was constructed in the late 1970s. The North Ash Pond (NAP) was constructed in two phases in 1982 and 1983. The NAP and WAP ponds continued to receive CCR until the Company converted the station to natural gas in 2014. *Id.* at 86. That process involved sluicing ash directly to the WAP; the ash was then hydraulically dredged to the NAP as needed to make room in the WAP. *Id.* at 120-21.

According to witness Williams the EAP and WAP at Bremo were considered "inactive" ash ponds under the CCR Rule. As such, DENC proceeded expeditiously to close the inactive ponds at Bremo by consolidating the EAP and WAP into the NAP, which was the largest pond and the pond located furthest from surface waterways. Since April 20, 2015, ash from the East and West Ponds was excavated and consolidated in the North Pond. The consolidation activities continued through March 2019. DENC could not proceed further with closing the NAP because of the permitting moratoriums created by SB 1398 and SB 807 that were passed by the Virginia General Assembly in 2017 and 2018, respectively. *Id.* at 90.

Chesapeake

Chesapeake was commissioned in 1953 as a coal-fired power station and continued to operate until December 31, 2014. All CCR from Chesapeake was originally managed in a single, onsite ash pond. *Id.* at 87. In the early 1970s, the generating units at the site were converted to burn oil. However, the Company returned to burning coal at

Chesapeake in the 1980s. By this point, EPA had passed the Clean Air Act (CAA), which required substantial improvements to the air pollution control equipment for new coal-fired units. In order to comply with the CAA, the Company installed pneumatic fly ash management and constructed a landfill permitted by Virginia DEQ on top of the historic ash pond to handle the dry fly ash. *Id.* at 140. Bottom ash has been sluiced to a separate bottom ash pond. Both the landfill and bottom ash pond are located within the footprint of the original ash pond. The coal-fired generation units at Chesapeake ceased operations on December 31, 2014 and have been decommissioned. *Id.* at 87.

On November 13, 2018, DENC signed a Memorandum of Agreement (MOA) with the Commonwealth of Virginia pursuant to which the Company agreed to groundwater monitoring and closure steps for coal ash at Chesapeake consistent with the standards imposed by CCR Rule regulations. The bottom ash pond is the only portion of the Chesapeake ash complex subject to the CCR Rule. However, this pond was constructed on top of the historic ash pond without a liner system. The adjacent landfill (also constructed on top of the historic ash pond) is subject to a Virginia DEQ solid waste permit that requires groundwater monitoring of the entire ash complex. Therefore, although the historical pond and landfill are not subject to the CCR Rule, there is no way to distinguish groundwater from the bottom ash pond from that which is in contact with the historic ash pond. As such, the MOA was agreed to in order to ensure that the closure and monitoring of the historic ash pond and adjacent landfill would be consistent with the CCR Rule. All three of the ash facilities (original ash pond, landfill, and bottom ash pond) are slated for closure once necessary permits are obtained. Only minor closure activities have occurred within the Chesapeake ash facility. Between October 16, 2017, and March 9, 2018, a small amount of ash was removed from the bottom ash pond for recycling. However, with the passage of SB 807 all further removal activities were halted until such time as a path forward was directed by the Virginia General Assembly. *Id.* at 90-91.

Chesterfield

Chesterfield was commissioned in 1944 as a coal-fired power station. Sluiced fly ash and bottom ash at Chesterfield was originally managed in the Lower Ash Pond (LAP) and Upper Ash Pond (UAP) where it was wet sluiced from the station. The LAP was constructed in two phases in 1964 and in 1967 to 1968. The UAP was constructed in 1985 to receive sluiced ash from the station and dredged ash from the LAP. The station ceased sluicing ash in 2017 when the plant converted to dry ash management. Flue gas desulfurization (FGD) solids have been generated at the site since 2008 as a byproduct from scrubbers used to clean air emissions. The FGD sludge is primarily composed of calcium sulfate or gypsum, which is beneficially reused as wallboard quality gypsum. *Id.* at 86-87.

The CCR Rule required that DENC close both the UAP and LAP at Chesterfield. The Company has continued to operate coal-fired units at Chesterfield as a coal-fired station. To comply with EPA's CCR and ELG Rules, Chesterfield underwent a number of wastewater and environmental improvements in 2017 to transition from wet sluicing coal ash to a dry ash management system. In order to manage the dry coal ash, DENC constructed an onsite, permitted landfill. The onsite landfill has received dry ash since 2017. The Company began the process of closing the LAP and UAP pursuant to federal and state requirements. *Id.* at 90.

Clover

Clover was commissioned in 1995 as a coal-fired power station. The station has operated a dry fly and bottom ash system since it began to generate power. CCR has been taken to an onsite landfill for disposal, which is divided into three areas, or stages. Two landfill stages reached their maximum storage capacity in April 2003 and were subsequently closed in compliance with Virginia DEQ regulations. Since 2003, dry fly ash and bottom ash has been stored in Stage III of the landfill. Clover also has two sedimentation basins used for settling wastewater solids, including FGD, prior to removal and disposal to the landfill. The water from these ponds is recirculated and FGD wastewater is not discharged. These ponds have been in place and operated since 1995. *Id.* at 88.

Under the CCR Rule, DENC will be required to close both FGD basins at Clover. CCR has been removed from the FGD basins, and those basins have been retrofitted with a CCR Rule compliant liner. DENC maintains compliance with its state permits and other CCR Rule requirements related to its CCR units at the site. The removal of the first sedimentation basin began in 2017, and its replacement meeting the requirements of the CCR Rule was placed into service in 2018. The second sedimentation basin was removed and construction was scheduled to be completed by June 2019. *Id.* at 92.

Mt. Storm

Mt. Storm is located in Bismarck, West Virginia, and is part of DENC's operating system. Mt. Storm was first commissioned in 1965 and continues to operate as a coal-fired power station. Dry fly ash and bottom ash are stored in the onsite lined Phase B landfill that is permitted by the West Virginia Department of Environmental Protection (West Virginia DEP). The FGD sludge from Mt. Storm is beneficially reused in mine reclamation projects to neutralize mine acid runoff and in the manufacturing of Portland cement. Excess FGD sludge is disposed of in the onsite lined Phase A landfill. *Id.* at 88.

Mt. Storm historically managed ash contact water from the ash loading area and bottom ash hydro-bins in five small low volume waste treatment ponds (Pyrite Pond and Ponds A, B, C, and D). These ponds did not meet the liner standards of the CCR Rule but were needed for continued operation of the station. Therefore, the five original ponds were closed by removal and the contents were placed in the onsite Phase B landfill. The station then constructed a new pyrite pond and two low-volume wastewater treatment ponds in the location of the former ponds. The onsite landfills (Phase A and B landfills) and their liners meet the CCR Rule's definition of an active landfill and, as such, have been allowed to continue to operate under the CCR Rule. The closure of these ponds and construction of new ponds meeting the requirements of the CCR Rule began in early 2016. The majority of the removal and construction was completed in 2018. Construction of the final pond's concrete liner was scheduled to be completed in Spring 2019. DENC continues to maintain compliance with its state permits and CCR Rule requirements related to its CCR units at the site. *Id.* at 92-93.

Possum Point

Possum Point was commissioned in 1948 as a coal-fired station. CCR management involved sluicing wet fly and wet bottom ash to five onsite ash ponds. These ponds were named Ash Ponds A, B, C, D, and E. Ponds A, B, and C are contiguous and were used as water treatment ponds to settle and manage low-volume wastewaters containing CCR from approximately 1955 to 1967. *Id.* at 85. The A, B, C ponds were in an inactive state and were partially covered in vegetation until compliance activities under the CCR Rule began in 2016. *Id.* at 103-04. When the ponds were closed in 1967, there were no applicable capping or closure standards. *Id.* at 104. The original Pond D was constructed in the early 1960s before Ponds A, B, and C reached capacity and received CCR until 1971. The Company completed construction on a new Pond E in 1968. In 1986, Pond E was nearing capacity, so the Company began construction on a new Pond D embankment to provide additional onsite storage space. The new Pond D was constructed with a 12" thick clay liner system. Ponds D and E continued to accept ash until the station's coal units were converted to natural gas in 2003. *Id.* at 85-86. After 2003, Pond E continued to receive low-volume wastewater streams from the plant, but not coal ash, until CCR Rule compliance activities began. *Id.* at 109.

The CCR Rule included provisions for "inactive" ash ponds that no longer received CCR after October 14, 2015. Ash ponds meeting the definition of "inactive" were required to close within three years or otherwise be subject to long-term monitoring and other costly provisions of the CCR Rule. DENC's ash ponds at Possum Point qualified as "inactive" under the CCR Rule. Accordingly, DENC proceeded expeditiously to close the inactive ponds at Possum Point by consolidating the contents of Ponds A, B, C, and E into Pond D, which is the largest pond at this site, is the furthest from waterways, and is also the only pond at Possum Point with a liner. In 2018, DENC completed the excavation of ash from Ponds A, B, C, and E. DENC could not proceed further with closing Pond D because of the permitting moratoriums created by SB 1398 and SB 807 that were passed by the Virginia General Assembly in 2017 and 2018, respectively. *Id.* at 89.

Virginia City

Virginia City was commissioned in 2012. All fly ash and bottom ash from the station is collected from the power station and moved by truck to the lined, onsite Curley Hollow CCR landfill. The landfill has a state-of-the-art design including a synthetic liner and leachate collection/treatment systems. *Id.* at 87.

Beginning in May 2016, DENC began installing additional wells and monitoring groundwater at Virginia City to comply with the CCR Rule. DENC is required to monitor these wells semi-annually. DENC continues to maintain compliance with its state permits and CCR Rule requirements related to its CCR units at the site. *Id.* at 91.

Yorktown

Yorktown began operation in 1957. Similarly to Chesapeake, the Company converted its coal-fired units to oil and then converted them back to burn coal in the 1980s. *Id.* at 141. In 1985, DENC constructed a lined solid waste landfill on an adjacent parcel of property owned by DENC. Since that time, the dry fly ash and bottom ash has been loaded on trucks and hauled to the adjacent CCR landfill. The Yorktown CCR landfill is permitted by the VA DEQ and is equipped with a bottom liner and leachate collection and treatment systems. *Id.* at 87.

The Company permanently closed over 60% of the landfill in 2017, and the remainder of the landfill will be permanently closed in 2019. *Id.* Witness Williams testified that the Company is closing its CCR facilities in accordance with state and federal requirements. *Id.* at 93.

In response to questions from the Commission witness Williams described DENC's CCR pond closure plans prior to the CCR Rule. He testified that at Possum Point the Company ceased using Ponds A, B and C in 1967. According to witness Williams, the ponds were left "in a static state." Witness Williams described this as placing soil over certain portions of the ponds where the Company needed access to equipment and infrastructure, such as transmission lines. No cover or cap was placed on the ponds. No vegetation was planted over the ponds. Any vegetation that grew in the ponds was natural regrowth that reseeded and spread. Further, no water was removed from the ponds. The water in the ponds was left to evaporate and migrate by what witness Williams described as "natural attenuation." Further, there was no groundwater monitoring of Ponds A, B and C, until it was required by the CCR Rule in 2016. Tr. vol. 5, 102-07, 124. Witness Williams testified that this same approach was taken by the Company at Bremo for the East Pond. He stated that the East Pond ceased receiving CCRs in the mid-1980s. *Id.* at 117-19. He further testified that this was the Company's closure plan for all of its CCR ponds, and that its plans were consistent with "regulatory allowed option[s]," until the CCR Rule and SB 1355 mandated different closure requirements. He stated that the Company had no written pond closure plans or written plans for post-closure activities.

Witness Williams further testified that there were no written Company documents evidencing an analysis of closure plan choices, or costs and benefits of different options, other than the plan developed for Chesterfield in the 1990s as a part of the NPDES permit. Tr. vol. 8, 20-25, 40-41. He also testified that prior to the CCR Rule the Company intended its CCR ponds to be "permanent disposal from the beginning." *Id.* at 41-42.

In addition, witness Williams testified that this same closure approach was taken by the Company at Possum Point Pond E when it was closed in 2003, with the exception that Pond E had groundwater monitoring wells installed in 1990, as required by its NPDES permit. *Id.* at 108-10.

Witness Williams described the Company's decision-making process in deciding to convert to lined dry ash landfills at Yorktown and Chesapeake in 1985, and at Clover when it was constructed in 1995. He stated that he was "not 100% sure" whether studies were conducted to determine the costs and benefits of converting to dry ash handling at other coal plants, but that he would make an inquiry. Tr. vol. 8, 50-55.

Witness Williams testified that the Company is a member of the Electric Power Research Institute (EPRI), and that the Company regularly consults EPRI publications "in some areas," although he had not worked directly with EPRI on coal ash. Tr. vol. 5, 129.

Witness Williams testified that the Company kept no records of the amount of CCRs deposited in its ponds annually or otherwise. He stated that DENC provided the Public Staff with estimates of the amounts of CCRs in its ponds based on the design and size information for each pond, and that this information was reflected in Lucas Exhibit 5. Tr. vol. 5, 146, 150-51.

In response to cross-examination by the Public Staff witness Williams stated that elevated concentrations of constituents were detected by DENC at Possum Point prior to the 1986 Virginia DEQ Special Order. Tr. vol. 5, 154.

With respect to Chisman Creek, witness Williams testified that shortly after 1974 the contamination was discovered at the site, and it was later placed in the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) program. He stated that DENC stepped in as the responsible party when the contractor that operated the site was not able to remediate it. Tr. vol. 5, 158.

Direct Testimony of Public Staff Witness Lucas

Public Staff witness Lucas recommended an equitable sharing of the Company's CCR management, remediation, and waste management unit closure costs. In conjunction with Public Staff witness Maness, he recommended that 40% of these coal ash related costs should be paid by the Company's shareholders, and the remaining 60% be paid by ratepayers. Tr. vol. 6, 110.

Witness Lucas noted that the Public Staff's equitable sharing recommendation is not based on the prudence standard, which would have resulted in a 100% disallowance of imprudently incurred costs. *Id.* at 113. Witness Lucas explained that the Public Staff Advocated for an equitable sharing approach rather than a prudence review because "some impacts are not clearly imprudent or reasonable," "because estimating historic costs to remediate environmental impacts would be speculative," and "the incomplete records of DENC and the challenge of reconstructing all the Company's decision-making on CCR management make it difficult, if not impossible, to conduct a prudence review." *Id.* at 184-85. On cross-examination witness Lucas confirmed that he had not identified any specific CCR-related costs that the Company incurred or undertook between July 1, 2016, and June 30, 2019, that were imprudent or unreasonable. *Id.* at 298-99.

Witness Lucas explained that the Public Staff's equitable sharing recommendation is based in part on culpability for environmental contamination, *id.* at 113, and in part on the magnitude and nature of the costs, as discussed by Public Staff witness Maness. Witness Lucas stated that it would be unreasonable to charge ratepayers for all the Company's CCR-related costs where the Company, and not the ratepayers, is culpable for those costs. *Id.* at 186. Specifically, he stated that "DENC has culpability for non-compliance with environmental regulations that are meant to protect groundwater and surface water from contamination by CCR constituents," and that "DENC's past management of coal ash has resulted in a risk of future contamination that EPA and the Virginia legislature have determined requires costly new management and closure requirements." *Id.* at 112-13.

Witness Lucas discussed a set of historic academic, industry, and regulatory documents that "demonstrate that, by the early 1980s, the electric generating industry knew or should have known that the wet storage of CCR in unlined surface impoundments was detrimental to the quality of surrounding groundwater and surface water." *Id.* at 141-42. Specifically, he discussed a 1979 report published by a research group from Arthur D. Little, Inc., and the Industrial Environmental Research Laboratory of the EPA that found that CCRs stored in "[w]et impoundments have the potential for contributing directly to groundwater contamination," and that lining impoundments would minimize such contamination. *Id.* at 142. Witness Lucas described the 1982 Manual for Upgrading Existing Disposal Facilities (EPRI Manual), published by the Electric Power Research Institute (EPRI), which stated that the use of surface impoundments "has fallen into disfavor with the EPA," and that "[w]hile groundwater can be protected and leachate generation can be minimized with sound engineering design and site operation, monitoring of groundwater and leachate, is nevertheless necessary to provide convincing proof of a safe disposal practice." *Id.* Witness Lucas testified that in 1988 the EPA issued a report to Congress in which it described how the use of liners, leachate collection systems, and groundwater monitoring had increased in the preceding years. *Id.* at 143-44. To illustrate this trend, he provided the following language from the 1988 report:

> Only about 25 percent of all facilities have liners to reduce off-site migration of leachate, although 40 percent of the generating units built since 1975 have liners. Additionally, only about 15 percent have leachate collection systems; about one-third of all facilities have ground-water monitoring systems to detect potential leachate problems. Both leachate collection and ground-water monitoring systems are more common at newer facilities.

Id. at 143.

Witness Lucas further stated that Dominion had failed to improve its CCR management practices despite the evolving knowledge of the risk of unlined CCR storage at the time. *Id.* at 144. According to witness Lucas, "[A]s publications from 1979 and later warned of the risks of CCR constituents leaching into groundwater from unlined storage ponds, DENC and other utilities should have installed comprehensive groundwater monitoring well networks to determine if the risk was materializing at their ash ponds." *Id.* He added that the Company had a duty to comply with groundwater quality standards regardless of accepted industry practice, noting Virginia and West Virginia's groundwater regulations and anti-degradation policies. *Id.* at 185. He explained that both Virginia and West Virginia have anti-degradation policies that require, broadly, that the quality of state waters be maintained. *Id.* at 125-26. Later, when asked during redirect examination, he read the anti-degradation policy from the Virginia Administrative Code into the record:

> If the concentration of any constituent in groundwater is less than the limit set forth by groundwater standards, the natural quality for the constituent shall be maintained. Natural quality shall also be maintained for all constituents, including temperature, not set forth in groundwater standards. If the concentration of any constituent in groundwater exceeds the limit in the standard for that constituent, no addition of that constituent to the naturally occurring concentration shall be made.

Id. at 306.

Witness Lucas stated that the Company had never installed voluntary groundwater monitoring wells at its coal-fired generating facilities and had only installed wells when required by state regulators to do so. *Id.* at 175. He testified that groundwater monitoring began at different dates for different sites, with monitoring beginning in the 1980s for some impoundments, in 2000 for impoundments at the Bremo facility, and as late as 2016 for historic Possum Point Ponds A, B, and C. These dates are shown on Lucas Exhibit 1. *Id.* at 175. He added that "DENC did not engage in comprehensive groundwater monitoring until even later," as shown on Lucas Exhibit 1. *Id.*

Witness Lucas confirmed on cross-examination that the Public Staff had not in the 1970s, 1980s, 1990s, or 2000s recommended that the Company install comprehensive groundwater monitoring, told the Company that its CCR management was not "sufficiently modern," or told the Company that it was not "sufficiently mitigating environmental impacts from its CCR impoundments or landfills." *Id.* at 299-300. Witness Lucas explained that "the Company, to my knowledge, didn't try to recover any costs like we're doing today that were created by groundwater contamination." *Id.* at 299.

Witness Lucas also testified regarding exceedances of groundwater standards at the Possum Point facility in the 1980s and discussed subsequent regulatory actions at that facility arising from those exceedances. *Id.* at 145-57. He explained that the facility had installed groundwater monitoring wells in 1985 as required in its National Pollutant Discharge Elimination System (NPDES) permit, and that samples from those wells had detected exceedances of groundwater standards in the vicinity of Ponds D and E. *Id.* at 145. Those exceedances resulted in a Special Order between the Virginia DEQ and the Company, which required further assessment of the contamination and an evaluation of remediation options. *Id.*

Witness Lucas also provided testimony regarding historic groundwater exceedances at the Chesapeake and Chesterfield facilities, as well as at the Chisman Creek CERCLA site, which witness Lucas explained was a site where a private contractor disposed of coal ash generated at DENC's Yorktown facility.[18] *Id.* at 157-63. Witness Lucas explained that at Chisman Creek the coal ash was disposed of in abandoned sand and gravel borrow pits between 1957 and 1974, and in 1980, when a neighboring well owner reported discolored water, the State Water Control Board found elevated levels of trace metals in groundwater, surface water, and soils. *Id.* at 162-63. Later, in 1986 and 1988, the EPA signed Records of Decision with objectives for remediation of the site. *Id.* at 163. He testified that the contamination affected drinking water to the level that the Company had to provide municipal water to nearby residents. He stated that this should have been an indicator to the Company that coal ash was capable of creating groundwater contamination. *Id.* at 337. Witness Lucas noted that the Chisman Creek site was mentioned in the preamble to the CCR Rule as an example of mismanagement of coal ash. *Id.* at 315.

Further, witness Lucas stated that these historic site investigations and exceedances "have shown evidence of degradation of the natural groundwater quality as a result of the Company's coal ash disposal practices." *Id.* He then testified that because of the absence of Company historical records concerning decisions made to construct new CCR waste management and disposal units or modify existing units, that the "Company is not able to demonstrate, with the records it has available, that it fully accounted for and mitigated the risks of CCR contamination in prior decades of CCR disposal and management." *Id.* at 165.

In addition, witness Lucas discussed groundwater contamination reported by the Company, and presented charts and maps of groundwater exceedances at each facility for the years 2017 and 2018 in Lucas Exhibits 12, 13, and 14. *Id.* at 176-79. He specifically noted 548 groundwater exceedances,[19] and explained that there will likely be additional exceedances reported due to inactive CCR surface impoundments now being required to collect and report groundwater monitoring data under the CCR Rule. *Id.* at 178-79. In response to questions from the Commission witness Lucas stated that the 548 groundwater exceedances showed statistically significant exceedances over natural background levels, maximum containment levels and/or groundwater protection standards. *Id.* at 308. He also explained on redirect examination that as the Company caused the groundwater to be degraded by failing to take steps to prevent leaching of ash constituents from its surface impoundments, it was in violation of the anti-degradation policies of Virginia and West Virginia. *Id.* at 306-07. Lastly, Witness Lucas noted that "[t]he lifetime compliance record for the Company's CCR impoundments is incomplete due in part to the lack of data retained by DENC," and that the Public Staff believes the Company had additional exceedances of groundwater standards at its CCR impoundments "over a long period of time." *Id.* at 179-80.

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[18] Witness Lucas also briefly discussed exceedances at the Company's Yorktown facility, which he explained were "the result of current or historical activities upgradient of the land and facility wells." Tr. vol. 6, 162.

[19] Witness Lucas explained in his direct testimony that groundwater standards under the CCR Rule can differ from those adopted by Virginia and West Virginia. The standards in the CCR Rule are based on national maximum containment levels (MCLs) established by the EPA and are health-based.

With respect to the Company's records witness Lucas testified that the Company was unable to locate and produce a number of historical NPDES/Virginia Pollutant Discharge Elimination System (VPDES) permits and groundwater monitoring reports and provided a list of missing documents. *Id.* at 168-72. He also testified that the records the Company was able to provide were not in a useful format, and that it was not possible from the Company's records "to identify all groundwater exceedances caused by CCR over the life of the Company's CCR units." *Id.* at 170-71. Witness Lucas also referred to a stipulation between the Company and the Public Staff, admitted as Lucas Exhibit 9, wherein the Company acknowledged its inability to provide historic records pertaining to groundwater conditions at its coal-fired generating facilities, as well as the fact that "it is not feasible to reconstruct a complete history of exceedances from Dominion's existing records." *Id.* at 172.

Witness Lucas summarized the following environmental legal actions filed against DENC:

> *Sierra Club v. VEPCO*, U.S. Court of Appeals, Fourth Circuit, Case No. 17-1895 (2018) – Plaintiff alleged surface water and groundwater violations at Chesapeake. The Fourth Circuit affirmed the trial court's conclusion that arsenic was reaching surface waters via groundwater, but held that the ash basins and landfill were not point sources under the Clean Water Act.
>
> *In re James River Association* – Appeal by JRA from a decision of the Virginia DEQ issuing a modified VPDES permit allowing the discharge of wastewater from Bremo. VEPCO and JRA entered into a settlement in 2016, with VEPCO agreeing to guarantee a minimum amount of treatment for coal ash wastewater.
>
> *In re Prince William County* - Appeal by PWC from a decision of the Virginia DEQ issuing a modified VPDES permit allowing the discharge of wastewater from Pond D at Possum Point. In 2016, VEPCO and PWC settled, with VEPCO agreeing to guarantee a minimum amount of treatment for coal ash wastewater.
>
> *Potomac Riverkeeper Network v. State Water Control Board* – Appeal by PRN from a decision of the Virginia DEQ issuing a modified VPDES permit allowing the discharge of wastewater from Pond D at Possum Point. In 2016, the Circuit Court upheld the permit modifications and dismissed the appeal.
>
> *State of Maryland v. State Water Control Board* – Appeal by Maryland from a decision of the Virginia State Water Control Board (VWCB) issuing a modified VPDES permit allowing the discharge of wastewater from Pond D at Possum Point. In 2016, VEPCO agreed to stricter wastewater testing standards, and Maryland withdrew its appeal.

> *West, et al. v. VEPCO* (VA Circuit Court) – In April 2018, two property owners adjacent to Possum Point filed complaints alleging groundwater contamination by coal ash ponds. The case is pending.

Id. at 131-36.

In concluding his discussion of the Public Staff's equitable sharing recommendation witness Lucas testified that the costs the Company has incurred for CCR management, remediation, and waste unit closure activities are related to groundwater contamination and environmental degradation. He stated that the CCR Rule and Virginia SB 1355 "were enacted in response to environmental contamination caused by CCR surface impoundments," and that the coal ash related costs the Company is seeking to recover are to comply with requirements that are "designed specifically to remediate ash basin environmental impacts that arose before the enactment of the CCR rule." *Id.* at 182. According to witness Lucas:

> DENC created the risk of coal ash contamination, their original disposal of CCR has led to actual environmental contamination in several instances, their original disposal of CCR poses an ongoing contamination risk that requires expensive remediation in the judgment of the EPA and the Virginia legislature, and ratepayers will not receive any additional electric service for this costly remediation.

Id. at 185.

When asked during cross-examination why the Public Staff's sharing recommendation in this case differs from those in the recent DEC and DEP rate cases, Docket Nos. E-7, Sub 1146 and E-2, Sub 1142, respectively — and specifically, why the Public Staff has found DENC to be less culpable than DEC and DEP — witness Lucas responded that DENC has not been found guilty of criminal negligence with respect to its management of waste coal ash facilities, has not had significant state regulatory enforcement actions, and that there is less evidence at this point of the extent of environmental impacts than were present in the DEC and DEP rate cases. *Id.* at 265.

Lastly, witness Lucas was asked on cross-examination whether the Public Staff are environmental regulators. *Id.* at 275. He responded that they are not and referred to a Public Staff response to a data request that stated the following: "The Public Staff is not a regulator. It is a consumer advocate working in a regulatory forum. . . . However, the costs of environmental compliance or the costs of non-compliance which the Company seeks to recover from ratepayers are within the jurisdiction of the Public Staff . . . ." *Id.* at 285-86. Witness Lucas was also asked about testimony submitted by a Public Staff engineer, Evan D. Lawrence, in a docket for an application for a Certificate of Public Convenience and Necessity for an electric merchant plant, in which witness Lawrence stated that "the Public Staff does not have particular expertise in the area of impacts of electric generation on the environment." *Id.* at 282-83. Witness Lucas explained that the cited testimony was taken out of context and was unrelated to cost recovery or a rate case. He further explained that witness Lawrence's testimony dealt with a certificate of public convenience and necessity for construction of a solar photovoltaic merchant electric generating facility, and that the purpose of his testimony was to discuss compliance of the application with applicable requirements, to discuss any concerns with the application, and to make a recommendation on the application to the Commission. *Id.* at 283-84.

Direct Testimony of Public Staff Witness Maness

Public Staff witness Maness described the Company's adjustments related to deferral of its CCR expenditures made to a regulatory asset. Those adjustments include: (1) the elimination of CCR-related accounting entries made in the Company's books and records during and before 2019 for financial accounting purposes; (2) a pro forma adjustment to increase rate base to defer as a regulatory asset the CCR expenditures incurred in the Deferral Period; and (3) a pro forma adjustment to increase operations and maintenance (O&M) expenses to reflect the three-year amortization of CCR expenditures. Tr. vol. 6, 209-10.

Witness Maness explained that for financial accounting purposes the Company has recorded its CCR expenditures as an Asset Retirement Obligation (ARO) liability, based on the requirements of Topic 410 (Asset Retirement and Environmental Obligations) of the Accounting Standards Codification (ASC 410) promulgated and maintained by the Financial Accounting Standards Board (FASB). *Id.* at 210-11. At the hearing witness Maness explained that when an ARO is established for financial accounting, the Company makes estimates of future costs and then "they basically discount that to be the present value as of today, using an appropriate discount rate, and they put that on their financial statements for financial investor purposes as a liability." *Id.* at 253. He further explained that at the same time the Company establishes the ARO it establishes an asset retirement cost (ARC) as an asset on its balance sheet. Next, to flow the ARC through expense over a period of time, the Company will depreciate it into the future in future financial statements using a depreciation method, or, if it's a retired asset such as a coal plant, the Company writes it off to expense immediately. *Id.* at 254. As an example, witness Maness stated:

> [I]n some cases, you may have an asset retirement obligation for a generating plant where the actual expenditures are not going to take place until many years into the future. So in that case, they will go ahead and record expenses -- they'll depreciate over the life of the plant. And they will incur those expenses at some future time, but they --or those expenditures, but they will be recording an expense as they go along without actually spending any cash at all. In other cases, you may have, such as we have for some of the coal plants involved here, plants that have already been retired. And so they still may not make those expenditures for some time into the future, but they will go ahead and immediately, for financial

> statement purposes, record the entire asset retirement cost related to that plant as an expense in the period in which it arises.

Id. at 255-56.

Witness Maness explained that, in this proceeding, the Company has reversed the entries made on its books in association with the FASB-mandated CCR ARO liability and is proposing the deferral and amortization of actual expenditures made during the Deferral Period, in accord with standard ratemaking accounting practice. He stated that the Company followed a similar procedure for CCR expenditures in the 2016 DENC rate case, and that the Public Staff agreed in concept with the Company's deferral approach in 2016 and, at that time, entered a Stipulation with the Company, which was approved by the Commission. Witness Maness testified that the terms of the Stipulation expressly stated that it did not prejudice the right of any party to take issue with the amount or treatment of any deferral of ARO costs in a future rate case proceeding. Given the magnitude of the costs involved in this proceeding, witness Maness stated that the Public Staff believes that continued deferral has been reasonable. *Id.* at 214.

In this proceeding witness Maness recommended the following adjustments to the Company's CCR expenditures:

> 1. Calculation of the return between July 1, 2016, and June 30, 2019, using annual compounding, rather than monthly compounding;
>
> 2. Amortization of the balance of deferred coal ash expenditures as of June 30, 2019, over a 19-year period [later updated to 18 years], rather than the 3-year period proposed by the Company; and
>
> 3. Reversal of the Company's inclusion of the unamortized balance of coal ash expenditures in rate base. This reversal, in conjunction with the 19-year amortization period, produces an equitable and reasonable sharing of the burden of coal ash expenditures between the Company's ratepayers and its shareholders.

Id. at 215-16.

Witness Maness stated that the Company's recommended amortization period is too short for costs of the magnitude and nature of CCR costs. Further, he noted that his recommendation for a longer amortization period, when coupled with the exclusion of the unamortized balance from rate base, would result in an equitable sharing of the costs between shareholders and ratepayers.

Witness Maness stated that there are two general reasons why the equitable sharing of CCR costs is appropriate in the present case. The first reason is that some degree of equitable sharing is appropriate because DENC has culpability for past environmental contamination and for creating a risk of future contamination from coal ash as discussed by Public Staff witness Lucas. The second reason is that some level of sharing is appropriate and reasonable because of the magnitude and nature of the costs. *Id.* at 218-19.

Witness Maness testified that equitable sharing of certain costs is appropriate without a specific finding of imprudence. He stated several reasons why equitable sharing is appropriate for CCR expenditures, including:

- The total amount of the costs is large (approximately $377 million on a system level and approximately $22 million on a North Carolina retail level), which amounts to approximately $179 per North Carolina retail customer, or $60 per year per North Carolina retail customer, before considering the impact of including the unamortized amount in rate base.

- DENC will be incurring significant additional costs in the future related to the CCR Excavation Act (Virginia Senate Bill 1355).

- The incurrence of these costs will not provide any benefits to customers in terms of additional electric service or improvements to service.

- The incurrence of CCR costs has not been the result of economic analysis that pointed toward an action that would be economically advantageous to ratepayers.

- And finally, he noted that the Commission has implemented equitable sharing in several past circumstances involving incurred costs that did not provide any future benefits to retail customers.

Id. at 220-22.

Witness Maness stated that the circumstances of this case, including the culpability of the Company and the magnitude and nature of the costs, as well as the levels of sharing approved by the Commission in past cases, led the Public Staff to its recommendation that shareholders bear 40% of the Deferral Period CCR costs (which results in a 19-year amortization period based on the rate of return initially recommended by the Public Staff, or an 18-year amortization based on the stipulated rate of return). Witness Maness stated that the Public Staff would likely recommend some level of sharing of costs even in the absence of culpability due to the magnitude and/or nature of the costs involved.

Witness Maness explained that the Public Staff's equitable sharing is achieved by first removing the unamortized amount of deferred expenses from rate base. As a result of that adjustment, the Company would not be allowed to earn a return from ratepayers on the unamortized balance while the deferred costs are being amortized.[20] The second step is to choose an amortization period that will result in a reasonable and appropriate sharing of the costs over time. *Id.* at 222. Maness Late-Filed Exhibit 1 shows the sharing percentages achieved by five- and ten-year amortization periods, in addition to the 18-year amortization period recommended by the Public Staff in witness Maness' supplemental testimony.

Relying on advice of counsel, witness Maness testified that excluding deferred expenses or losses from rate base is legal under North Carolina law. The Public Staff's position is that the only costs the Commission is required to include in rate base pursuant to N.C.G.S. § 62-133(b)(1) are the public utility's property that is used and useful, or, in some circumstances, the costs of construction work in progress. Again relying on advice of counsel, witness Maness stated that N.C.G.S. § 62-133(d) operates separately from N.C.G.S. § 62-133(b), and requires the Commission to "consider all other material facts of record that will enable it to determine what are reasonable and just rates." The Public Staff asserted that N.C.G.S. § 62-133(d) provides the Commission with discretion to authorize equitable sharing where appropriate to achieve reasonable and just rates. *Id.* at 223.

Witness Maness explained that the Commission has approved equitable sharing in several past cases, including in the cases of plant abandonment losses. Specifically with regard to DENC, witness Maness stated that the Commission has found that a ten-year amortization period, with no return, was appropriate to fairly allocate the loss between the utility and the consumer for Surry Unit 3, Surry Unit 4, North Anna Unit 3, and North Anna Unit 4. *Id.* at 223-25; *see* Docket No. E-22, Sub 273, Seventy-Third Report of the North Carolina Utilities Commission, pp. 354-55. Furthermore, witness Maness incorporated by reference the North Carolina Supreme Court decision affirming the equitable sharing of costs between ratepayers and shareholders with regard to Carolina Power & Light Company's (CP&L) Harris plant cancellation costs. Tr. vol. 6, 226-28; *see State ex. rel. Utilities Com. v. Thornburg*, 325 N.C. 463, 385 S.E.2d 451 (1989).

Witness Maness testified that the Commission has also found that an equitable sharing of costs was appropriate for the environmental cleanup costs associated with manufactured natural gas plants (MGPs) in its October 7, 1994 Order Granting Partial Rate Increase in Docket No. G-5, Sub 327. Tr. vol. 6, 228. The MGP sites were the subject of "investigations under environmental laws." According to witness Maness, the Commission ordered an equitable sharing for the environmental cleanup costs of Public Service Company of North Carolina, Inc., (PSNC), and specifically found:

> 29. The unamortized balance of MGP costs should not be included in rate base. The resulting sharing of clean-up costs between ratepayers and

[20] As discussed elsewhere in this Order, the Public Staff agrees with allowing recovery of financing costs incurred between the beginning of the Deferral Period and the date rates approved in this proceeding become effective (when amortization begins).

shareholders will provide PSNC motivation to minimize costs and to pursue contributions from other potentially responsible parties and insurers.

Order Granting Partial Rate Increase, *Application of Public Service Company of North Carolina, Inc., for an Adjustment of its Rates and Charges*, No. G-5, Sub 327, at 6 (N.C.U.C. Oct. 7, 1994) (MGP Order).

Turning to whether the CCR costs are used and useful, witness Maness explained that "used and useful" only applies to a utility's property and not to a utility's expenses incurred in the operation, maintenance, and disposal of that property. Tr. vol. 6, 229-30. Witness Maness argued that DENC's deferred CCR costs are not "property used and useful" under N.C.G.S. § 62-133(b)(1) because (1) most of the costs in this case were incurred for operating expenses, and (2) the Commission authorized deferral of those expenditures to a regulatory asset. In particular, he testified that:

(1) In data responses to the Public Staff, the Company has stated that the vast majority of the CCR expenditures made from January 2015 through June 2019 would be charged to expense if the FASB and FERC USOA [Federal Energy Regulatory Commission Uniform System of Accounts] ARO accounting requirements did not exist.

(2) Even for those items that might be capitalized costs of property in the absence of the FASB and FERC USOA ARO accounting requirements, the Company has itself chosen to request a regulatory accounting and ratemaking method that does not explicitly account for any coal ash compliance costs, either in the past or in the future, as the capitalized costs of property, but instead accounts for them as expenses, with a proposed regulatory asset intended to provide for the recovery of expenses incurred in the past. Although the Company could have chosen to propose following a different method, whereby it might specifically identify capital costs separately and include them in rate base, depreciating them over their useful lives, while accounting for other expenses on an ongoing basis, it did not. Instead, the Company has proposed to utilize an accounting and ratemaking model that accounts for and recovers the coal ash cleanup costs as expenses on an as-spent basis, without specific identification of, or accounting for, any costs as plant in service or other property.

Id. at 231-32.

In addition, witness Maness addressed the issue of whether the classification of the deferred CCR costs as "working capital" is appropriate. Witness Maness stated that in his opinion the classification is a matter of convenience and the "proposed deferred coal ash compliance costs are expenses incurred in the past that the Company proposes to recover in the future; they have nothing to do with the Company's forward-looking obligation to provide utility service." *Id.* at 232. To clarify the appropriate scope of working capital, witness Maness provided the following description from Charles F. Phillips, Jr. in his treatise on utility regulation:

> Working capital – the funds representing necessary investment in materials and supplies, and the cash required to meet current obligations and to maintain minimum bank balances – is included in the rate base so that investors are compensated for capital they have supplied to a utility.

Id.; *see* Charles F. Phillips, Jr., *The Regulation of Public Utilities 348* (3d ed. 1993). Since the CCR deferred costs neither enable nor facilitate the provision of current or future utility service, consistent with the Charles Phillips definition, witness Maness asserted that those costs cannot be classified in substance as "working capital," and thus are not required to be included in rate base.

Witness Maness testified that when a return is denied on coal ash costs, the degree of sharing is a function of the length of the amortization period: "as the delay in the recovery period increases, the utility's financing costs increase, and the burden of the loss of the time value of money on the ratepayers decreases." Tr. vol. 6, 234. To achieve a sharing that results in ratepayers bearing approximately 60% of the present value of deferred costs at the net-of-tax overall rate of return witness Maness recommended, in his direct testimony, a 19-year amortization period. *Id.* at 235.

Witness Maness stated that the 60%-40% sharing ratio is a qualitative judgment that the Public Staff believes is reasonable and appropriate based on the magnitude and nature of the costs and the extent of DENC's culpability for coal ash environmental contamination, as addressed in the testimony of witness Lucas. *Id.* The recommendation for a lesser sharing burden on investors in this case than was recommended in the recent DEC and DEP rate cases (approximately 50%-50% sharing) is based on the lesser extent of environmental contamination attributable to DENC's coal ash waste management units, as determined by witness Lucas.

Witness Maness additionally stated that the Public Staff would very likely recommend some level of sharing even in the absence of environmental culpability, due to the magnitude and/or nature of the costs. *Id.* at 237-38. In DENC's Sub 532 general rate case, the Public Staff agreed to an amortization period of five years with the unamortized balance included in rate base. However, at that time the total paid-to-date system costs were only 22% of the system-wide Deferral Period CCR costs at issue in this case. Additionally, as described by witness Lucas, there was almost no evidence in the Sub 532 record of environmental problems created by DENC's coal ash storage facilities, in contrast to the present case. *Id.* at 238-39.

In supplemental direct testimony Public Staff witness Maness adjusted his sharing recommendation amortization period from nineteen years to eighteen years based on the Public Staff Stipulation. *Id.* at 246. He explained that the overall rate of return agreed to in the Stipulation affects the number of years of amortization needed to achieve the recommended sharing allocation. Due to the increase in the rate of return from that initially recommended by the Public Staff, the amortization period necessary to achieve an approximate 60%-40% sharing decreased to eighteen years. The sharing percentage is approximate: eighteen years produces a ratepayer sharing of 59.212%, which is the closest to 60% sharing that can be achieved using the stipulated rate of return and whole years without the ratepayer portion exceeding 60%. *Id.* at 247.

Witness Maness also adjusted the North Carolina jurisdictional amount of the CCR deferred costs to reflect the compounding of DENC's return on those costs on an annual basis, as agreed to by DENC, rather than on a monthly basis, as initially proposed by DENC. The adjusted North Carolina jurisdictional amount is $21,841,000. Maness Supplemental Exhibit 1, Schedule 1.

Rebuttal Testimony of DENC Witness Williams

Company witness Williams' rebuttal testimony responded to the direct testimony of Public Staff witnesses Lucas and Maness regarding the Public Staff's recommended "equitable sharing" disallowance. Witness Williams observed that the Public Staff's disallowance theory largely rests on its opinion that DENC was "culpable" for creating a risk of groundwater contamination that has led to actual environmental contamination attributable to the Company's CCR waste management facilities. Tr. vol. 7, p. 52. He also noted that the Public Staff argued that "equitable sharing" would be appropriate even without "culpability" solely because of the magnitude of DENC's requested costs. According to witness Williams "culpability" suggests wrongdoing. He noted that the Public Staff has acknowledged that it is not capable of or willing to identify a specific action the Company could have taken in the past, and that witness Lucas previously testified in the 2018 DEP Rate Case, in which the Public Staff also recommended equitable sharing based on DEP's historical ash management practices:

> We can't go back in time and say, oh, they should have put in a clay liner in 1978 or done dry ash stacking in the 1980s. I mean, that's impossible to go back and put all these "what ifs" together and say exactly here's what they should have done. And here's what would have been the cost, and that cost would have been in the rates today for customers.
>
> . . .
>
> [T]hat's going back to the past. Somebody could have gone back and said what you should have done back at a certain time. And that's — you could be talking about the prudence, and I can't go back and — I can't go back and tell you exactly what would have happened what you should have done at a certain time. I'm not sure what good it would have done . . . .

Id. at 52.

Witness Williams contended that this case should be focused on determining whether the identifiable CCR costs that the Company incurred from July 1, 2016 through June 30, 2019, were the result of reasonable and prudent decisions made at the time the costs were incurred. He maintained that DENC's costs are reasonable and prudent because the Public Staff did not recommend a single, specific cost disallowance related to DENC's CCR impoundments or landfills. *Id.* at 56.

Witness Williams also questioned whether it was within the Public Staff's purview and scope of expertise to evaluate the Company's compliance with environmental regulations and standards. He noted that neither the Company nor the Public Staff could find any example prior to 2016 where the Public Staff had raised any concerns regarding groundwater or surface water issues related to CCR or CCR management strategies at any of DENC's facilities. *Id.* at 57-58; Company Rebuttal Exhibit JEW-1. He noted that it has been the Public Staff's position that it is not an environmental regulator, and environmental regulation of DENC's CCR impoundments and landfills is the responsibility of state agencies such as the Virginia DEQ and West Virginia DEP, and that when a utility complies with the directives of its environmental regulators, it has been the position of the Public Staff that such actions would not be considered mismanagement. Witness Williams testified that if the Public Staff's role did not involve evaluating the Company's CCR management practices when the management decisions were made, the Public Staff cannot argue that its role in the present case involves second-guessing the decisions of the Company and its environmental regulators decades later. Tr. vol. 7, 59.

Witness Williams further questioned the Public Staff's role and expertise regarding environmental issues in light of testimony submitted by the Public Staff in May 2019 in Docket No. EMP-103, Sub 0. In that case, Albemarle Beach Solar, LLC applied for a certificate of public convenience to construct an 80-MW solar facility in Washington County, North Carolina. An issue in the docket was the potential environmental impacts of the solar project. According to witness Williams, the Public Staff did not opine on those potential environmental issues and testified:

> [T]he Public Staff does not have particular expertise in the area of impacts of electric generation on the environment. Those issues are best left to the purview of environmental regulators who do have this expertise, and who are responsible for issuing specific environmental permits for electric generating facilities. To that end, as stated below, the Public Staff recommends that the Commission require compliance with all permitting requirements . . . .

Id. at 59-60.

Witness Williams noted that the Public Staff witness who offered the testimony in Docket No. EMP-103, Sub 0 held the same position within the Public Staff – Utilities Engineer, Electric Division – as witness Lucas. Based on the Public Staff's statements about its role and the scope of its expertise, witness Williams opined that witness Lucas' testimony was unreliable. *Id.* He also commented that the Public Staff's recent attempts to take on the role of a hindsight environmental regulator would promote inefficiency and inconsistency within the utility industry. It would be inefficient because environmental regulators already consider and understand the potential impacts of their decisions, such as when and to whom to issue permits, when and where to require and not require groundwater monitoring, or how potential impacts, if manifested, should be addressed. The Public Staff is attempting to second-guess those efforts but without the requisite level of expertise. It would promote inconsistency because having utilities be subject to the Public Staff's hindsight environmental review would potentially undermine the decisions, judgment, and expertise of environmental regulators. *Id.* at 62.

Witness Williams also responded to the Public Staff's criticisms of his expertise and ability to testify regarding historical CCR management decisions made by the Company. He testified that those criticisms are unfounded. He testified that he was a professional geologist with almost twenty years of groundwater remediation and waste management experience. This experience included five years that he spent with VA DEQ, where he was the lead staff on reviewing coal ash regulations following the TVA dam failure in 2008. His role was to not only provide expertise in coal ash, but to also provide guidance regarding Virginia's groundwater requirements and their history. Witness Williams testified that while at the Company he has also become proficient in West Virginia's groundwater regulations and their application to DENC's Mt. Storm facility. Since the Public Staff's recommended disallowance is largely based on alleged groundwater issues at DENC's sites in Virginia and West Virginia, he explained that he was extremely well-qualified to explain the Company's CCR management decisions with respect to groundwater in those states. Additionally, he explained that he was well-positioned to discuss the history of CCR management at DENC's facilities. In his role as Director of Environmental Services, he was responsible for overseeing environmental compliance at all of DENC's coal-fired plants. That role required that he understand how those plants and CCR storage facilities have been historically operated. Additionally, he reviewed historical regulatory reports as well as the studies cited by witness Lucas and explained that he was well-qualified to understand those materials in their proper context and to draw meaningful and reasoned conclusions from them. *Id.* at 60-61.

Witness Williams next addressed witness Lucas' criticisms and characterizations of DENC's historical CCR management practices and environmental compliance history. Witness Williams disagreed with witness Lucas' contention that the electric generating industry knew or should have known that wet storage of CCR in unlined surface impoundments was detrimental to the quality of surrounding groundwater and surface water. He observed that none of the articles, reports, or studies cited by witness Lucas condemn or recommend the elimination of the use of unlined impoundments. Further, he explained that unlined surface impoundments are not by their very existence "detrimental" to groundwater and nearby surface water. He explained that EPA reports from the 1980s through the 2000s show that site specific and regional factors must be considered to evaluate potential impacts to water quality from surface impoundments. In addition, he stated that if impacts are discovered that does not mean that the public or environmental health has been threatened. *Id.* at 64-65.

Witness Williams testified that much context was missing from witness Lucas' testimony regarding the Company's historical management practices. He opined that the Public Staff's testimony was devoid of any qualitative analysis of the evolving knowledge of potential impacts from CCR management practices. He explained that understanding the extent and nature of potential impacts is crucial to determining whether the Company adequately managed its CCR. He also testified that one should consider how different actions may have impacted DENC's ability to reliably generate electricity to meet demand and other economic impacts. While surface impoundments are now being regulated out of existence, witness Williams explained that surface impoundments were originally constructed as an environmental solution to address concerns about air emissions from coal-fired plants. Those concerns resulted in the adoption of emission control technologies to collect CCR, which previously would have been emitted into the air, and direct the CCR via water to surface impoundments serving a water treatment function. According to witness Williams, EPA's approach to regulating CCR has evolved significantly over time, ultimately culminating in the CCR Rule. *Id.* at 65-66.

To show that evolution, witness Williams summarized the major federal regulatory determinations and reports affecting CCR from the 1970s through the promulgation of the CCR Rule. Those determinations and reports reflected EPA's findings after considering the available scientific and industry knowledge. Witness Williams testified that, until the CCR Rule, EPA's position was to defer to state agencies, like VA DEQ and WV DEP, to regulate CCR and determine whether industry practices were sufficiently protective of the environment. He testified that it was not until 2010, when the draft CCR Rule was published, that EPA first proposed actions to address potential environmental risks from unlined surface impoundments. According to witness Williams, that is because prior to the CCR Rule EPA had concluded that a one-size-fits-all federal regulatory approach was not deemed necessary to address region-specific conditions and risks. Even then, one of EPA's proposals would have allowed the continued use of unlined surface impoundments until they reached the end of their useful lives. *Id.* at 65-73.

Witness Williams opined that DENC responded reasonably and appropriately to evolutions in industry practices and regulatory approaches for CCR management by following the directives of its state regulators. Witness Williams described the regulatory regimes in Virginia and West Virginia that were applicable to its CCR surface impoundments and landfills. He explained that Virginia first adopted groundwater regulations in 1977. From 1977 until 1998, Virginia DEQ's regional offices evaluated groundwater risks at CCR facilities through requirements placed in the Company's VPDES, Virginia Pollution Abatement (VPA) permits, and solid waste permits. Additionally, he explained that local governments were also able to require groundwater monitoring through conditional use permits issued for certain CCR storage facilities. He testified that in 1998, VA DEQ developed a policy (the 1998 VA DEQ Guidance) to promote consistent standards amongst its six regions, which included guidance on when to require groundwater monitoring, how monitoring wells should be installed, the parameters that should be considered for monitoring, the proper methods for collecting and analyzing samples, determining the need for and execution of risk assessment, and selecting remedial methods, if needed. He explained that under the 1998 VA DEQ

Guidance ultimate responsibility for determining whether groundwater monitoring was necessary was delegated to the permit writer, who was a member of the Virginia DEQ staff with specialized expertise. If groundwater monitoring was determined to be necessary, the permit writer could require DENC to develop a groundwater monitoring plan (GWMP). Witness Williams testified that Virginia DEQ adopted a phased approach for groundwater monitoring. The first phase would typically involve a small number of wells (minimum of one upgradient and two downgradient). If potential groundwater impacts were detected during the first phase, a second phase with additional monitoring wells could be required. He testified that based on the groundwater monitoring data received (i.e. constituents, detected levels, extent of plume, proximity of plume to receptors), Virginia DEQ could then determine whether a risk assessment was necessary. If Virginia DEQ identified a potential risk, then it could require remedial action, which could range from requiring closure, excavation, or lining of surface impoundments. However, he explained that Virginia DEQ would have selected a remedial option that was commensurate with the risks posed by the potential impacts. If impacts or potential off-site risks were deemed not to be harmful, Virginia DEQ could determine that leaving the groundwater alone (i.e. natural attenuation) at that point may be all that is necessary. *Id.* at 74-75. Similarly to Virginia DEQ, the West Virginia DEP was responsible for overseeing the State's solid waste program applicable to CCR storage. As of 1987, all CCR disposal sites in West Virginia were required to meet leachate, waste confinement, and aesthetic standards, and there were provisions for groundwater monitoring and final cover requirements. *Id.* at 76.

Witness Williams testified that by 1988, when the EPA published its report to Congress, DENC was monitoring groundwater at all but one of its active Virginia stations pursuant to Virginia DEQ requirements and standards. He testified that by 2000 the Company was monitoring groundwater at all of its Virginia stations, and that at the Company's Mt. Storm facility in West Virginia, groundwater monitoring began in 1987 after DENC received its NPDES permit to construct the CCR landfill. Witness Williams stated that similar to the approach taken in Virginia, an exceedance of a groundwater standard in West Virginia was not managed as a violation warranting a penalty. Instead, DENC would have been required to take additional steps to evaluate groundwater quality, including increasing the frequency of sampling, adding parameters to monitor, and assessments for potential remedial action. Witness Williams explained that West Virginia DEP never required corrective action for groundwater exceedances. *Id.* at 75-77.

Based on what he described as the robust regulatory oversight that was in place in Virginia and West Virginia and DENC's compliance with regulatory directives, witness Williams disagreed with witness Lucas' contention that the Company did not install comprehensive groundwater monitoring well networks to evaluate potential groundwater impacts from CCR surface impoundments. He noted that witness Lucas did not explain what he meant by "comprehensive monitoring" or how it would differ from what the Company had already been doing, and that witness Lucas provided no meaningful and necessary details to explain what "comprehensive monitoring" should have occurred, including how many background and monitoring wells should have been installed, the location of wells, the constituents to be monitored, or the frequency of testing. *Id.* at 78-

79. Further, witness Williams noted that witness Lucas did not explain why Virginia DEQ and West Virginia DEP's judgment regarding the necessity for and scope of groundwater monitoring should be ignored in favor of witness Lucas' undefined, hindsight standard. Considering that DENC's state environmental regulators did not believe that installing extensive groundwater monitoring networks was necessary or appropriate for all sites, witness Williams questioned whether DENC's economic regulators, including this Commission and Virginia State Corporation Commission, would have deemed costs to install and monitor unnecessary wells to be reasonable. *Id.* at 80.

Witness Williams explained that DENC and its state regulators took a measured approach to assess and mitigate potential risks from CCR storage facilities. He testified that DENC collected groundwater data in accordance with its environmental permits, and it submitted that data to its environmental regulators for review and analysis. In the event of exceedances he explained that regulators on some occasions used their expertise and professional judgment to require further action, including increasing monitoring frequency, increasing the number of constituents to be sampled, requiring the installation of new wells, or requiring the preparation of site characterization studies to evaluate potential risks. Witness Williams testified that in all cases the Company complied with any additional actions required by its environmental regulators to mitigate risks and protect the environment. He noted that for all of DENC's lined and unlined surface impoundments, state environmental regulators reissued permits allowing the Company to continue to dispose and store CCR in those impoundments. He opined that had environmental regulators determined that DENC's CCR storage areas posed a threat to human health or the environment, they would not have continued to renew those operating permits and would have required more corrective actions. *Id.* at 80-81. Witness Williams also testified that witness Lucas could not explain how groundwater monitoring different than what had been historically required by Virginia DEQ and West Virginia DEP (i.e. "comprehensive groundwater monitoring well networks") would have changed the Company's CCR management practices or avoided the present-day costs that the Company is seeking to recover in this case. *Id.* at 81-82.

Witness Williams also responded to witness Lucas' contention that DENC, as an industry leader, was responsible for setting the industry standards. Although witness Lucas was apparently critical of those industry standards, witness Williams noted that witness Lucas did not explain or define what the industry standard should have been, nor did he argue that DENC's compliance with the industry standard and applicable laws was unreasonable or irrelevant. According to witness Williams, witness Lucas insinuated that DENC should have moved well ahead of accepted science, regulatory requirements, and industry practice by taking unspecified measures to prevent any and all groundwater quality impacts regardless of cost, despite likely interruptions to electric service, and without evidence of any potential harm to human health or the environment. *Id.* at 83.

Witness Williams rejected witness Lucas' assertion that the Company was or should have been aware of environmental degradation caused by its CCR because of environmental studies that were conducted at Possum Point, Chesapeake, Chesterfield, and Yorktown. Witness Williams opined that the existence of exceedances, alone, did not mean that the Company harmed the environment or otherwise mismanaged its CCR. He explained that the existence of past and present groundwater exceedances reflects historical construction practices and the evolution of groundwater assessment and corrective action under modern laws. He testified that EPA was aware that the design of ash basins had resulted in groundwater concerns throughout the industry; however, EPA determined that immediately closing basins, which would require shutting down operating coal plants, would be more harmful to human health and the environment than taking a measured approach. Witness Williams testified that DENC's state regulators focused on whether the exceedances were causing, or had the potential to cause harm to, any on- or off-site receptors to determine whether mitigation measures were necessary. The existence of an exceedance of applicable standards at a particular location was not evidence of actual or potential harm; rather, it was a data point that informs whether and to what extent further study is required to assess potential risk. Witness Williams cited the 1998 Virginia DEQ Guidance which stated that "risk assessment ultimately determines whether some measure of remediation needs to be completed." He then pointed out that none of the reports cited by witness Lucas indicated any risk to offsite human health or ecological receptors. *Id.* at 83-86.

Witness Williams testified that the reports cited by witness Lucas actually show that DENC was diligently monitoring groundwater to determine whether further mitigation measures were necessary. He testified that when Virginia DEQ did require follow-up measures the Company took appropriate measures. He rejected witness Lucas' contention that the Company did not follow the directives of its regulators regarding groundwater issues at Possum Point. He pointed out that witness Lucas' own exhibit showed that the Company did, in fact, comply with a Special Order issued by the State Water Control Board, which was confirmed by the cancellation of that order in 1991. Witness Williams also clarified that the report relating to groundwater issues at Yorktown that was cited by witness Lucas had nothing to do with CCR. *Id.* at 84-85. Regarding witness Lucas' reference to Chisman Creek and the Battlefield Golf Club site, witness Williams testified that those sites were irrelevant to the issues in this case because neither site is subject to the CCR Rule, neither site was owned by DENC when contamination occurred, and neither site managed CCR in surface impoundments or landfills. *Id.* at 86-88. Likewise, witness Williams testified that the legal matters cited by the Public Staff were also irrelevant and misleading because witness Lucas did not argue that the existence of those cases was evidence of wrongdoing, mismanagement or harm to the environment. *Id.* at 88-89.

Witness Williams also responded to the Public Staff's criticisms of the discovery process, which he opined was merely a distraction. He represented that he and his staff made good faith efforts to locate, collect, and then produce information and documents spanning almost four decades of the Company's operations. He estimated that DENC employees spent over 250 hours searching for and collecting information, culminating in the production of decades' worth of CCR-related documents to the Public Staff. He noted that the Public Staff never filed a motion to compel, despite claiming DENC's responses were inadequate. He also testified that he was not aware of any legal requirement or business reason to retain decades-old permitting materials, especially when the

Company could not have foreseen that the Public Staff would, decades after the CCR storage facilities were constructed, be scrutinizing the Company's historical CCR management practices. Witness Williams explained that witness Lucas' testimony regarding purported examples of discovery deficiencies and instances of non-responsiveness was misleading, irrelevant, and false. *Id.* at 89-92.

Witness Williams also rejected the Public Staff's claim that it did not have enough information to evaluate the Company's environmental compliance history. As the Public Staff did not conduct a prudence review, nor did it have any intent to do so, it was unclear to witness Williams how additional information regarding historical CCR management decisions would have been helpful or relevant to the Public Staff. Responding to witness Lucas' testimony regarding the lack of groundwater reports prior to 2000, witness Williams testified that DENC did provide the Public Staff with a spreadsheet showing all of the approximately 300,000 groundwater monitoring results going back to the beginning of monitoring for each site, each of which would have been provided to VA DEQ or WV DEP. He opined that DENC's compliance history could be judged by its regulators' response to those monitoring results:

- DENC's environmental regulators did not require the Company to retrofit its existing impoundments with liners;
- DENC's environmental regulators did not require the Company to close its existing impoundments;
- DENC's environmental regulators did not require the Company to excavate CCR from its existing impoundments;
- DENC's environmental regulators authorized the Company's continued use of its existing impoundments;
- DENC's environmental regulators authorized the Company to continue disposing of CCR in its existing impoundments; and
- DENC's environmental regulators, where potential groundwater impacts were identified, required further monitoring, risk assessments, or corrective action.

He testified that, while Virginia DEQ and West Virginia DEP had the authority to do so, they never saw a sufficient environmental justification for requiring DENC to change its CCR management practices. Further, he opined that in the absence of any environmental justification the Company would not have been able to make an economic justification to its shareholders and customers for overhauling its operations. He testified that the Public Staff's assertion that "missing" groundwater data would have shown additional evidence of degradation was speculation, was not scientifically supported, and was not consistent with the regulatory record. Moreover, he testified that it would be speculation built on speculation to suggest that additional evidence would have triggered any different action by environmental regulators or the Company. He opined that recent groundwater data collected under the CCR Rule, which did not show risks to human health or the environment, confirmed that additional data would not have spurred state regulators to require changes to the Company's CCR management practices. *Id.* at 92-94.

Witness Williams concluded his rebuttal testimony by showing that the Public Staff's hindsight review of the Company's historical CCR management practices was unfair and not productive. He noted that the Public Staff and the Commission knew about and never objected to the continued use of surface impoundments and landfills in North Carolina. He explained that burning coal and storing the by-products was essential to providing reliable electricity in the region for decades. Witness Williams conceded that present and future CCR costs were significant but that the Company was minimizing those costs to the degree possible. He expressed his concern that the Public Staff's recommended disallowance of admittedly prudent and reasonable costs through "equitable sharing" was shortsighted and could lead to an unpredictable and unhealthy regulatory environment for utilities and their customers. *Id.* at 96-97.

Rebuttal Testimony of DENC Witness McLeod

Witness McLeod noted that the Public Staff agrees and makes no objection to the Company's ongoing deferral accounting treatment of CCR costs. Tr. vol. 6, 665. He also addressed each of the Public Staff's three recommended adjustments set forth in the testimony of witness Maness. First, he stated that the Company accepts as reasonable the Public Staff's recommended adjustment to use annual compounding rather than monthly compounding for financing costs incurred on CCR ARO expenditures during the deferral period of July 1, 2016 through June 30, 2019. Witness McLeod noted that this change reduces the Company's Adjustment NC-33 by $23,000. *Id.* at 667.

Witness McLeod next explained the Company's opposition to witness Maness' purported justification for the Public Staff's proposed equitable sharing approach. As a threshold matter, witness McLeod noted that neither witness Lucas nor witness Maness identified any specific CCR-related costs that the Public Staff alleges to be imprudent or unreasonable. *Id.* at 667. Witness McLeod underscored that the appropriate regulatory standard for denial of cost recovery is a finding that a specifically identified cost has been imprudently incurred or that the level of cost incurred is unreasonable. In the absence of an allegation of imprudence or unreasonableness, witness McLeod found the Public Staff's proposal to be "standard-less," subjective, and inappropriate. *Id.* at 669. For example, witness McLeod noted that the Public Staff can point to no methodology that would support its selection of the proposed 60/40 sharing split. Noting witness Maness' concession that the Public Staff subjectively selected a sharing ratio, then "backed into" the mechanism necessary to achieve that level of disallowance, witness McLeod highlighted that the Public Staff chose differing percentages for equitable sharing in each of the instances in which it has advocated for adoption of the principle—50/50 in the DEP rate case, 51/49 in the DEC rate case, and 60/40 in the instant case. *Id.* at 670. In witness McLeod's view, the Public Staff's "qualitative judgment" with respect to the proposed disallowance is inappropriate as a regulatory cost recovery approach.

Witness McLeod next refuted witness Maness' contention that the Commission should treat the Company's request to recover its prudently incurred CCR costs the same as it did costs associated with abandoned nuclear plants. In particular, witness McLeod noted that abandoned nuclear plant costs are not comparable to the costs of CCR remediation and closure of waste management facilities because—unlike CCR generating plants—abandoned nuclear plant costs were never used and useful in providing utility service to customers. *Id.* at 672. Moreover, witness McLeod noted that the Commission rejected this comparison in the recent DEP and DEC rate cases.

Witness McLeod likewise disagreed with witness Maness' contention that the Commission's prior treatment of environmental clean-up costs of manufactured gas plants (MGPs) supports an equitable sharing of coal ash costs. In particular, witness McLeod noted a few key differences between MGP and coal ash costs. First, at the time of clean-up, the majority of MGP sites had not been used in decades. In contrast, the Company's coal-fired generating units and/or the coal ash disposal facilities are either still providing services to customers or were providing service until very recently. *Id.* at 674-75. Second, the coal-fired generating plants that utilized the coal ash disposal facilities have always been in the ownership of the Company or its predecessors. Most MGP sites, on the other hand, had several owners before being acquired by the regulated gas utilities that eventually undertook MGP clean-up. *Id.* at 675.

Rather than rely on the ill-fitting analogies put forth by witness Maness, witness McLeod urged the Commission to adopt the cost recovery methodology used by this Commission in the 2016 DENC Rate Case in Docket No. E-22, Sub 532 and the DEP and DEC rate cases that were heard in 2018 in Docket Nos. E-2, Sub 1142 and E-2, Sub 1146, respectively. *Id.* at 676. In each of those cases, witness McLeod noted, the Commission found the relevant CCR expenditures to be used and useful because they were included in the working capital section of the rate base and were investor-furnished rather than ratepayer-furnished funds. *Id.* at 679.

In addition witness McLeod stated that he did not believe the eighteen-year amortization period proposed by the Public Staff would be in the best interests of either North Carolina customers or the Company. He noted that a longer amortization period costs customers more in the long run and delayed recovery of these deferred costs puts more pressure on rates in the future as the company will continue to incur significant additional environmental expenditures related to CCR regulatory compliance in the coming years.

Finally, witness McLeod noted that witness Maness' proposal to account for CCR costs differently because they are an "extremely large cost" is not workable from a regulatory accounting perspective. Because the Public Staff and witness Maness have offered no explanation as to the definition of an "extremely large cost," adopting a regulatory order based on a subjective interpretation of the term is inconsistent with witness McLeod's experience of regulatory ratemaking and with known principles of regulatory accounting. *Id.* at 683. In this case the total rate changes in the stipulation provides for an overall rate decrease for the North Carolina jurisdiction. This includes amortization of the CCR regulatory over a five-year period with a return on the unamortized balance. According to witness McLeod, if the Public Staff's nineteen-year amortization proposal is adopted by the Commission the result will likely be overlapping vintages of CCR regulatory asset amortizations across multiple, future rate cases in which the Company will be requesting recovery of additional deferred CCR costs. The Company's proposed five-year amortization of these regulatory assets allows rates to be set at a just and reasonable level that positions the Company's current rate structure to recover these actually-incurred costs over a reasonable amount of time. *Id.* at 680-81.

DENC's Post-hearing Brief and Proposed CCR Order

DENC cited the Harris Order as the Commission's seminal standard of reasonable and prudent costs and stated that challenging prudence requires a detailed and fact intensive analysis, in which the challenger is required to: (1) identify specific and discrete instances of imprudence; (2) demonstrate the existence of prudent alternatives; and (3) quantify the effects by calculating imprudently incurred costs.

Further, DENC cited N.C.G.S. § 62-133(b)(1), and stated that the Commission must "[a]scertain the reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service rendered to the public within the State, less that portion of the cost which has been consumed by previous use recovered by depreciation expense." In addition, DENC noted that in applying the reasonable and prudent and used and useful standards, the Commission must apply the appropriate burden of proof to the Company's and intervenors' arguments. DENC argued that it incurred the CCR compliance costs at issue, supported by its application and the direct testimony filed in this case, and, therefore, it has met its prima facie burden. Moreover, DENC contended that its evidence was unrebutted because the Public Staff failed to identify or justify discrete disallowances under the applicable imprudence standard. As a result, DENC asserted that it is entitled to recover its CCR costs.

DENC maintained that the theory of "culpability" relied upon by the Public Staff is incompatible with the reasonable and prudent standard because Public Staff witness Lucas could not identify any specific CCR actions or costs that DENC should or could have taken prior to 2016. According to DENC, CCR impoundment closure, even under the supervision of state regulatory agencies, is a site-specific undertaking with procedures that have evolved over time and continue to do so, and in the absence of federal regulatory standards and guidelines to follow, no one can say what the prudent course would have been, even if one acts on the assumption that DENC was imprudent to await promulgation of the federal environmental regulatory requirements.

The Company asserted that it followed the prevalent and cost-effective approach, which was to install monitoring wells iteratively and methodically to best identify harmful groundwater contamination, and that it provided substantial, competent evidence that its historical CCR management practices have been reasonable and prudent. DENC submitted that absent any credible evidence that DENC's design, operation, or construction of its surface impoundments fell below applicable industry or regulatory standards, the Commission should conclude that the Company's historical CCR practices were reasonable and prudent.

Further, DENC contended that it appropriately responded to advances in industry practices for managing CCRs and cited numerous EPA and other reports that it maintained support its position. Moreover, the Company asserted that without an environmental justification to upgrade or retrofit its surface impoundments with liners, leachate collection or other remedial measures, taking such actions would not have been prudent or economically justifiable.

DENC further contended that absent specific findings of imprudence the Public Staff's recommended equitable sharing disallowance is not justified. The Company noted that the Commission did not accept the Public Staff's equitable sharing concept in the 2018 DEP and DEC Rate Cases and contended it should likewise refuse to do so here. In particular, DENC stated that the equitable sharing approach is without standards, and, therefore, would be arbitrary for purposes of disallowing identifiable costs.

With regard to the amortization period over which the CCR costs should be recovered, DENC submitted that an amortization period of five years would be reasonable and appropriate. The Company stated that the Public Staff's proposed amortization period of eighteen years, with no return, would be arbitrary and unfairly punitive to DENC. Further, DENC asserted that because it appropriately applied ARO accounting, the Company is eligible to earn a return on the amortized CCR costs.

In summary, DENC requested that the Commission find by the greater weight of the evidence that the Company's CCR closure expenses incurred over the period from July 1, 2016, through June 30, 2019, are (a) known and measurable, (b) reasonable and prudent, and (c) used and useful, and are, therefore, recoverable in rates.

Public Staff's Proposed CCR Order

The Public Staff stated that one argument underpinning its equitable sharing recommendation is that the Company knew or should have known in past decades that its unlined coal ash impoundments had the potential to contaminate groundwater and surface water. The Public Staff pointed to the testimony of witness Lucas in which he identified a series of historical documents that showed a growing industry awareness of the risks of unlined surface impoundments, as well as a trend toward risk assessment and mitigation, and stated that based on these developments there was by 1979 a known risk of groundwater contamination from ash stored in unlined surface impoundments. In addition, Public Staff maintained that no evidence presented by the Company provided additional context that would contradict the assertion that the Company knew or should have known of the risks of its coal ash storage practices by the early 1980s.

The Public Staff further contended that in addition to the historical documents there were specific instances of actual environmental contamination that illustrated the risks of storing coal ash in unlined impoundments. As examples the Public Staff noted that the groundwater monitoring wells installed at the Possum Point facility in 1985 pursuant to the facility's NPDES permit detected violations of groundwater standards in the vicinity of Pond D and Pond E, resulting in a Special Order requiring further assessment of contamination and an evaluation of remediation options.

In addition, the Public Staff cited the Chisman Creek CERCLA site, at which coal ash generated at the Company's Yorktown facility had been disposed of in abandoned sand and gravel borrow pits between 1957 and 1974, causing groundwater, surface water, and soil contamination. The Public Staff contended that the Company should have known — given this actual evidence of environmental contamination both at its Possum Point facility and stemming from coal ash generated at its Yorktown facility and disposed of in unlined pits off-site — of the risks of contamination posed by unlined coal ash impoundments, and that DENC's actual experience at those locations provided knowledge of risk in the 1980s, in addition to the knowledge in the historical documents.

In addition, the Public Staff noted that it was unable to obtain information from the Company that would allow it to form a complete picture of the Company's past coal ash management. For example, the Public Staff cited witness Lucas' testimony that the Company was unable to provide groundwater monitoring reports for any of its facilities prior to the year 1999, as well as for select years after 1999, and that the Company could not locate a number of its past NPDES permits. The Public Staff also cited the records stipulation entered into by DENC and the Public Staff, and contended that the Company's inability to locate and provide historical documents and records concerning its past coal ash management practices is compounded by the fact that its primary witness on the matter of coal ash, witness Williams, only recently joined the Company in 2015, and, thus, does not have any first-hand knowledge of the Company's actual history of management of CCRs in prior years. Witness Williams' contention that he supplemented his knowledge by review of historical documents and records is difficult to square, the Public Staff contends, with the Company's inability to produce any significant quantity or quality of historical records.

Moreover, the Public Staff submitted that the weight of the evidence shows that the Company is culpable for groundwater contamination at its sites. The Public Staff stated that witness Lucas presented evidence that the Company had 548 exceedances of groundwater quality standards at its coal ash storage disposal sites, and contended that these groundwater exceedances show statistically significant exceedances over natural background levels, MCLs, and/or groundwater protection standards that are attributable to the migration of contaminants from the Company's coal ash disposal sites. In addition, the Public Staff maintained that the Company's failure in the 1980s to install comprehensive groundwater monitoring at its coal ash storage sites, and to use the data that could have been obtained from comprehensive monitoring to manage the risk of contamination, establishes DENC's culpability.

Further, the Public Staff urged the Commission to reject the Company's argument that complying with the directives of state environmental regulators is sufficient evidence that its coal ash management was reasonable and prudent, and to hold the Company to a standard based on whether a coal ash unit has the potential to contaminate the environment. The Public Staff maintained that the Commission should conclude that the Public Staff has presented sufficient evidence to show that environmental contamination from CCRs exists at all of the Company's coal ash disposal sites, and that the Company's coal ash impoundments pose a risk of future contamination that has required costly clean-up and closure to date and will require the further closure and excavation of ponds as mandated by the Virginia General Assembly.

According to the Public Staff, the Company bears culpability for not complying with state environmental regulatory policy to avoid degradation of groundwater. With respect to the role of the Public Staff and Commission, the Public Staff asserted that the Commission should find that witness Lucas has sufficient qualifications to provide competent testimony regarding the Company's environmental compliance history, and that the Public Staff has broad authority under the Act to investigate the Company's cost recovery requests in a general rate case.[21]

In addition, the Public Staff contended that the Commission has the authority and discretion to order an equitable sharing of coal ash costs based on findings that the Company did not comply with environmental regulations, that DENC contaminated groundwater, that DENC created a risk of future contamination that affects remediation costs, and that the magnitude and nature of CCR costs justify a sharing between ratepayers and shareholders. In this regard, the Public Staff cited N.C.G.S. § 62-133(d), as providing the Commission with discretion to order equitable sharing on the basis that "other material facts of record" justify an adjustment necessary to achieve "reasonable and just rates." The Public Staff contended that a rate-oriented equitable sharing decision under N.C.G.S. § 62-133(d) does not require the identification of particular or specific costs resulting from an imprudent decision or act of the utility, or necessarily preclude an after-the-fact or hindsight review, such as environmental contamination results.

Finally, the Public Staff asserted that the Stipulation entered into in DENC's 2016 Rate Case does not estop the Public Staff or Commission from fully examining the prudence and reasonableness of DENC's CCR costs.

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[21] Section 62-15(d) of the North Carolina General Statutes provides:

It shall be the duty and responsibility of the public staff to:

(1) Review, investigate, and make appropriate recommendations to the Commission with respect to the reasonableness of rates charged or proposed to be charged by any public utility and with respect to the consistency of such rates with the public policy of assuring an energy supply adequate to protect the public health and safety and to promote the general welfare;

(2) Review, investigate, and make appropriate recommendations to the Commission with respect to the service furnished, or proposed to be furnished by any public utility . . . .

AGO's Post-hearing Brief

The AGO contended that if DENC is allowed to recover its CCR costs it should not be allowed to add a rate of return to those costs. The AGO stated that only a utility's rate base, not its operating expenses, is eligible to earn a return, and that DENC failed to show that its CCR costs meet the test for inclusion in rate base because it has not shown that the costs are for property that is used and useful for providing current service to consumers. The AGO cited and discussed several North Carolina Supreme Court cases on the issues of rate base inclusion and property used and useful, including *State ex rel. Utils. Comm'n v. Pub. Staff-N.C. Utils. Comm'n*, 333 N.C.195, 202, 424 S.E.2d 133, 137 (1993) (*Carolina Trace*) (reversing Commission's order that put into rate base a wastewater connection that a utility was no longer using); *State ex rel. Utilities Com. v. Thornburg*, 325 N.C. 484, 495, 385 S.E.2d 463, 469 (1989) (*Thornburg II*) (reversing Commission's decision to put costs to construct excess nuclear facilities into rate base); and *State ex rel. Utilities Comm'n v. Carolina Water*, 335 N.C. 493, 507-08, 439 S.E.2d 127, 135 (1994) (*Carolina Water*) (reversing Commission's decision to put retired wastewater treatment plant into rate base).

The AGO maintained that DENC's CCR costs mainly involve expenditures made in preparing closure plans for CCR impoundments, treating contaminated groundwater, excavating coal ash, transporting it to other locations, and disposing of it, and that such costs are typically accounted for as operating expenses. Further, the AGO stated that the evidence indicates that the CCR costs were related to disposal of waste from power generation for electrical service that was provided in the past, instead of for property that is used and useful for providing electric service to current and future customers.

In addition, the AGO asserted that the costs to address coal ash do not become investment in rate base simply because the expenditures are useful for environmental compliance, and that environmental compliance costs can be reasonable and prudent, and thus recoverable as costs, and still fail the higher standard of being used and useful for providing current electric service, and thereby being allowed to earn a return.

Further, the AGO contended that the creation or existence of an ARO does not require that DENC's CCR costs be property used and useful, or to be used and useful within a reasonable time after the test period, in providing service rendered to the public, and that no exception to the used and useful requirement is provided for an ARO in the Act.

Finally, the AGO discussed several cases and asserted that our Supreme Court has not recognized any exception to the used and useful requirement based on funds being identified as working capital or as having been supplied by investors.

Discussion

Applicable Legal Principles

The Commission is required to set just and reasonable rates for public utilities. N.C.G.S. § 62-130(a). Just and reasonable rates are those that provide the utility an opportunity to earn a fair return on its property and are fair to the utility's customers. *State ex rel. Utilities Comm'n. v. Piedmont Natural Gas Co.*, 254 N.C. 536, 119 S.E.2d 469 (1961); *State ex rel. Utilities Comm'n. v. Duke Power Co.*, 285 N.C. 377, 206 S.E.2d 269 (1974).

The ratemaking process for the Commission to follow when deciding a general rate case is set forth in N.C.G.S. § 62-133. The statute makes clear that, in establishing rates for any public utility, the Commission "shall fix such rates as shall be fair both to the public utilities and to the consumer." N.C.G.S. § 62-133(a). Additionally, the statute requires the Commission to determine the utility's rate base. N.C.G.S. § 62-133(b). Finally, the statute provides that the Commission "shall consider all other material facts of record that will enable it to determine what are reasonable and just rates." N.C.G.S. § 62-133(d). As the North Carolina Supreme Court has noted, all sections of N.C.G.S. § 62-133 must be given weight in construing the language of any individual section of the statute. *Utilities Comm'n v. Duke Power Co.*, 305 N.C. 1, 18, 287 S.E.2d 786, 796 (1982).

To achieve just and reasonable rates, the utility's revenue must be sufficient to cover the utility's cost of service, plus allow the utility the opportunity to earn reasonable return on its rate base but must be fair to customers. To this end, the North Carolina Supreme Court has counselled:

> In sum, the fixing of "reasonable and just" rates involves a balancing of shareholder and consumer interests. The Commission must therefore set rates which will protect both the right of the public utility to earn a fair rate of return for its shareholders and ensure its financial integrity, while also protecting the right of the utility's intrastate customers to pay a retail rate which reasonably and fairly reflects the cost of service rendered on their behalf.

State ex rel. Utils. Comm'n. v. Nantahala Power & Light Co., 313 N.C. 614, 691, 332 S.E.2d 397, 474 (1985), *rev'd on other grounds*, 476 U.S. 953, 106 S. Ct. 2349, 90 L.Ed.2d 943 (1986), *appeal after remand*, 324 N.C. 478, 380 S.E.2d 112 (1989) (*Nantahala*).

When setting just and reasonable rates, the Commission must determine whether costs incurred by the utility were prudently incurred, which involves an examination of whether the utility's actions, inactions or decisions to incur costs were reasonable based on what it knew or should have known at the time the actions, inactions, or decision to incur costs were made. Harris Order at 14. Challenging prudence requires a detailed and fact intensive analysis, and the challenger is required to (1) identify specific and discrete instances of imprudence; (2) demonstrate the existence of prudent alternatives; and (3) quantify the effects by calculating imprudently incurred costs. Harris Order at 14-15.

Further, the “matching principle” dictates that customers who use an asset should pay for the asset at the time it is used. Put another way, the costs generated from a resource should be borne by the generation of customers that benefitted from the consumption of the resource. Thus, in striking the balance between shareholder and consumer interests, the Commission endeavors to avoid or minimize the extent to which present and future customers pay for costs incurred related to service provided in the past.

The burden of proof to show that rates are just and reasonable is on the utility. N.C.G.S. § 62-134(c). Nevertheless, intervenors have a burden of production in the event that they dispute an aspect of the utility’s prima facie case. *State ex rel. Utils. Comm’n v. Intervenor Residents of Bent Creek/Mt. Carmel Subdivisions*, 305 N.C. 62, 76, 286 S.E.2d 770, 779 (1982) (*Intervenor Residents*) (“The burden of going forward with evidence of reasonableness and justness arises only when the Commission requires it or affirmative evidence is offered by a party to the proceeding that challenges the reasonableness of expenses . . . .”). If the intervenor meets its burden of production through the presentation of competent, material evidence, then the ultimate burden of persuasion reverts to the utility, in accordance with N.C.G.S. § 62-134(c).

As relates to the Commission’s Order in DENC’s 2016 Rate Case, the Company asserts that “[f]undamental principles of fairness and due process dictate that the Company should be able to rely on the Public Staff’s prior position” regarding the ability of the Company to fully recover its coal ash expenditures. Tr. vol. 7, 58-59. In essence, the Company argued that the Public Staff is estopped from making a recommendation for the disallowance of costs based on the Company’s CCR management practices and environmental non-compliance because the Public Staff did not raise those concerns in decades past. *Id.* The Commission declines to accept this argument. The Company’s obligation to serve the public interest and comply with applicable laws applies irrespective of whether or when the Public Staff or any governmental oversight or regulatory body challenges its actions.

In addition, the Commission agrees with the Public Staff that the order in DENC’s 2016 Rate Case does not have precedential value with respect to the CCR issues in this case. Section VIII.D of the 2016 Stipulation between DENC and the Public Staff stated:

> Overall prudence of CCR Plan – The Public Staff’s agreement in this proceeding to the deferral and amortization of CCR expenditures incurred through June 30, 2016, shall not be construed as a recommendation that the Commission reach any conclusions regarding the prudence and reasonableness of the Company’s overall CCR plan, or regarding any specific expenditures other than the ones to be recovered in this case.

Agreement and Stipulation of Settlement at 10-11.

Likewise, the Commission's order in DENC's 2016 Rate Case expressly stated that the order should not be construed as a decision on the prudence and reasonableness of any CCR issues other than the CCR costs allowed in the 2016 proceeding:

> [F]urther, the Commission's determination in this case shall not be construed as determining the prudence and reasonableness of the Company's overall CCR plan, or the prudence and reasonableness of any specific CCR expenditures other than the ones deferred and authorized to be recovered in this case.

2016 DENC Rate Case Order at 63.

The evidence presented in DENC's 2016 Rate Case on the industry's and DENC's historical CCR practices and decisions was far less extensive than the evidence presented in the present case, mainly because the Company and Public Staff settled for the Company's recovery of its CCR remediation expenditures through June 30, 2016. As a result, the issues of prudence and reasonableness were not fully litigated and no significant evidentiary record was developed. Therefore, the Commission finds that it would be inappropriate to give the 2016 DENC Rate Case Order precedential effect for the treatment of costs the Company is seeking to recover in this proceeding.

Finally, the Commission's orders must be based on competent, material and substantial evidence in the record of the instant proceeding. N.C.G.S § 62-65(a)

Reasonableness and Prudence of CCR Costs

As a general rule, when the utility presents evidence that costs were reasonably and prudently incurred and no additional evidence of prudence and reasonableness is presented, a prima facie case is made that the costs were reasonably and prudently incurred. *Intervenor Residents*, 305 N.C. at 76-77, 286 S.E.2d at 779. In direct testimony, DENC witness Mitchell stated that the enactment of the final CCR Rule in April of 2015 created a legal obligation for the Company to close all of its inactive and existing ash ponds, and to engage in monitoring and corrective action as necessary. Virginia incorporated the CCR legislation in Virginia enacted on March 20, 2019, requires the Company to move ash to lined landfills and to recycle 6.8 million cubic yards of ash from at least two sites. Tr. vol. 4, p 176. DENC witness McLeod stated that the Company's proposed revenue requirement in this case includes recovery of expenditures made between July 1, 2016, and June 30, 2019 (Deferral Period) to continue compliance with state and federal regulations related to CCR at several DENC facilities. *Id*. at 251. In general, DENC witnesses McLeod and Williams testified that the CCR expenditures were prudently made and therefore should be recovered in rates.

Witness Williams was DENC's sole witness on the substance of the Company's management and storage of CCRs. Witness Williams is a geologist with extensive experience in advising companies on environmental compliance matters and was employed for five years with Virginia DEQ as the lead person on reviewing CCR regulations. Witness Williams testified that his knowledge of DENC's CCR disposal practices was derived from reading hundreds of internal documents and talking to many DENC employees. He concluded that DENC had been prudent and reasonable in its decisions and actions in handling and storing CCRs. The Commission is unable to assess the breadth or depth of witness Williams' claimed review of internal documents, since few CCR documents were offered into evidence and there was substantial dispute between the Company and Public Staff concerning the completeness of the Company's internal records concerning past CCR policy decisions and management practices. What follows is the Commission's assessment of the limited documentary record that was provided.

In the 1981 EPRI manual entitled *EPRI Coal Ash Disposal Manual* (2d ed. 1981), DEC Rate Case, Docket No. E-7, Sub 1146, Sierra Club Kerin Cross-Exam Exh. 4, at 3-1,[22] EPRI stated: "While most coal ash is currently handled in wet systems, the national trend is away from wet disposal systems toward dry handling methods." Indeed, DENC was a part of that national trend in 1985 when the Company converted to a lined dry ash landfill at Chesapeake and built a lined dry ash landfill at Yorktown, and in 1995 when the Clover plant was constructed using only dry ash handling with the ash disposed of in a lined landfill. As a result, wet sluicing of ash to unlined ponds was mostly discontinued other than at the Company's oldest plants, those constructed before the 1980s – principally Bremo, Possum Point, and Chesterfield. Further, in the 1960s, far ahead of its time, DENC built Pond D at Possum Point with a clay liner. Similarly, in the mid-1980s when DENC built a new Pond D at Possum Point, it also included a clay liner. The Commission gives significant weight to these demonstrations of the Company's forward thinking and prudence in its CCR management practices. The Company's leadership in dry ash handling has resulted in the avoidance of millions of tons of wet storage CCRs that would have to be remediated today at substantially greater cost than will be required to permanently close its landfills. However, the Commission observes that DENC could not establish that it studied or performed any cost benefit analysis regarding converting its coal-fired plants from wet ash handling facilities to dry ash handling facilities once it converted two of its plants in 1985 or after it constructed a new coal-fired plant with dry ash handling facilities in 1995.

In addition, there is substantial evidence regarding DENC's compliance with legal requirements for handling and storing CCRs that tends to show that DENC was attentive to the applicable legal standards of the day, as well as evolving standards. Other than the Virginia DEQ Special Orders on Possum Point, there is no evidence of DENC having been the subject of notices of violation, NPDES permit revocations, other remediation orders, or enforcement actions by environmental regulators. As witness Williams testified, unlined impoundments were the accepted repositories for storing CCRs prior to adoption of the CCR Rule, and compliance with the Clean Water Act and NPDES permits for water discharges was generally accepted as meeting the expectations of environmental regulators. Although the Commission does not view regulatory compliance as being

[22] The documents identified as being introduced in the DEC Rate Case, Docket No. E-7, Sub 1146, were introduced in this proceeding by the Public Staff by incorporation into witness Lucas' prefiled direct testimony.

prudence *per se*, such compliance is nonetheless evidence that could support a determination of prudence.

Further, the evidence shows that DENC cooperated fully with Virginia DEQ in responding to the Possum Point Special Orders and ultimately reached a resolution of the groundwater concerns at that plant that was acceptable to Virginia DEQ. Moreover, the evidence establishes that DENC acted prudently and responsibly in response to the water degradation that occurred at Chisman Creek. As witness Williams testified, that site became a CERCLA remediation site because of actions and omissions of an independent contractor, not DENC. The site was not a CCR surface impoundment managed by DENC when the release of contaminants occurred. Yet when the contractor did not take financial responsibility for the Chisman Creek clean-up, DENC did so.

The Commission concludes, based on the foregoing evidence, that DENC made a prima facie case that the expenditures made between July 1, 2016 and June 30, 2019 to continue compliance with state and federal regulations at several of its CCR sites were prudently made.

Neither the Public Staff nor any other party to the proceeding expressed opinion on the prudence and reasonableness of the CCR Costs. Instead, Public Staff witness Lucas testified to a number of deficiencies in the Company's historical management of CCRs and the resulting environmental impacts. The following evidence was provided by Public Staff witness Lucas and the Public Staff's exhibits:

- Witness Lucas testified that the earliest monitoring of groundwater and leachate by DENC began in December 1983, and that the Company did not engage in comprehensive groundwater monitoring until later. *See* Lucas Exhibit 1. That exhibit shows that there were eight CCR ponds for which the first groundwater sampling date was 2000 or later, as follows: one pond in 2000, two ponds in 2013, one pond in 2015, three ponds in 2016, and one pond in 2018.

- Witness Lucas recounted in detail DENC's studies and consultants' recommendations, totaling at least seven reports, in response to a 1987 Special Order of the Virginia State Water Control Board (VWCB) requiring DENC to remediate groundwater violations at Possum Point Ponds D and E. The VWCB issued another Special Order in 1989. Witness Lucas stated that DENC's consultant recommended that DENC construct a dry waste disposal site at Possum Point, but DENC decided not to do so. He opined that this appears to be unreasonable.

- Witness Lucas stated that a consultant's report that included a compilation of 2003 groundwater data for Pond E at Possum Point showed 49 statistically significant exceedances of dissolved constituents of barium, cadmium, copper, iron, manganese, nickel, phenols, potassium, sodium, and zinc. The report further stated that the data "suggests that historical activities in the area of [Ash

Ponds D and E] have degraded groundwater quality compared to background levels." Tr. vol. 6, 156.

- Witness Lucas' testified that he reviewed the Chisman Creek report, entitled *1990 Superfund Site Interim Closeout Report*, which stated that between 1957 and 1974 DENC hired a private contractor to haul fly ash from the Yorktown plant to four abandoned sand and gravel pits on the Yorktown property. Witness Lucas stated that Records of Decision were signed by EPA in 1986 and 1988 and included objectives for remediation.

- Witness Lucas' Exhibit 13 showed that DENC's CCR ponds had a total of 490 CCR Rule groundwater monitoring exceedances in 2017 and 2018. Witness Lucas testified that these records show repeated evidence of degradation of groundwater quality resulting from DENC's CCR disposal practices. Witness Lucas testified that a lack of documentation for many plants prior to 2000 leaves unanswered questions about what DENC knew when it made key decisions about CCR disposal.

In addition to the evidence presented by the Public Staff, a number of facts provided by witness Williams and the Company's documents highlight the risks taken by the Company with respect to its historical management of its CCR liabilities and call into question DENC's prudence, as follows:

- Prior to the effective date of the CCR Rule, DENC considered unlined ponds to be a permanent CCR disposal solution.

- Prior to the effective date of the CCR Rule, DENC's plan was to close all ponds in place.

- Closure in place was accomplished by partially covering the pond with soil, in a few instances, and allowing grass and other vegetation to reseed and spread over the surface naturally. No water was removed and no complete or engineered cap or cover was placed over the ponds. Because the impoundments were not dewatered when their use ceased, hydraulic pressure in the impoundments continued to facilitate the migration of ash constituents into the groundwater.

- There were no written closure plans detailing the steps to be taken when use of the impoundments to receive and temporarily store sluiced ash stopped, except the 2003 plan for Chesterfield.

- There were no written analyses, cost-benefit analyses, or reports on alternative storage options, other than the 1984 study for Chesapeake, and several studies in the 1980s for Possum Point.

As well, the following industry and government studies of which the Commission took judicial notice, taken separately and together provide evidence of industry best practices related to the management and disposal of CCRs.

1981

EPRI Coal Ash Disposal Manual (2d ed. 1981), DEC Rate Case, Docket No. E-7, Sub 1146, Sierra Club Kerin Cross-Exam Exh. 4, at 3-1 – "While most coal ash is currently handled in wet systems, the national trend is away from wet disposal systems toward dry handling methods."

1982

EPRI Manual for Upgrading Existing Disposal Facilities (Aug. 1982), DEC Rate Case, Docket No. E-7, Sub 1146, Sierra Club Kerin Cross-Exam Exh. 2 – Paragraph entitled "Effects on Groundwater" noted that "In general, inadequately lined ponds provide a greater opportunity for groundwater contamination, because the soil immediately below the pond is always saturated and under a constant head of pressure from the overlying water. Consequently, seepage may be constant and greater in volume than leachate from a landfill." *Id*. at 2-11 (footnote omitted).

Paragraph entitled "Identifying Design and Operational Deficiencies" noted that there are two possible standards, one being specific federal and state regulations, and the other being "[t]he site has the potential to contaminate the environment." The text goes on to state:

> [I]dentification and correction of regulatory deficiencies do not necessarily preclude the possibility of past or future environmental degradation by the site. Conversely, known degradation cannot be corrected by simply conforming to the regulations. State and federal waste disposal regulations are directed at those designing a new site or closing an old site, not for those wishing to upgrade and continue operating a substandard site.

Id. at 4-1 to 4-2.

1985

Full-Scale Field Evaluation of Waste Disposal from Coal-Fired Electric Generating Plants (Little Report, 1985), DEC Rate Case, Docket No. E-7, Sub 1146, Public Staff Wells Cross-Exam Exh. 6 – EPA funded report conducted by Arthur D. Little, Inc., involving a study of six coal-fired plants, one of which was DEC's Allen plant. The section entitled "Results and Conclusions for the Six Study Sites" included these two statements

> (2) Releases of most trace metals are generally within acceptable limits (e.g., drinking water and aquatic life standards) because of the combined effects of receiving water dilution and the chemical immobilization of most

> water-related species. Arsenic is a significant exception that would require case-by-case evaluation for analogous wastes. In this study, elevated concentrations of arsenic in the in-situ liquid phase and/or off-site mobility of arsenic were observed at three of the six sites.
>
> (3) In settings characterized by at least modest precipitation and fairly pervious soils where disposal occurs in direct hydrogeologic proximity to a subsurface drinking water supply or small, high-quality surface water body, an artificial disposal site liner may be needed to minimize contamination by (at least) the major species. A minimum liner thickness of about 0.5 m (1.5 ft) would suffice for proper engineering placement of soil-like liners.

Id. at 5-1.

1988

EPA Report to Congress entitled *Wastes from the Combustion of Coal by Electric Utility Power Plants*. On page 4-54, it notes that "More than 40 percent of all generating units constructed since 1975 use lined disposal facilities."

2004

EPRI Decommissioning Handbook for Coal-Fired Power Plants (Nov. 2004), DEC Rate Case, Docket No. E-7, Sub 1146, AGO McManeus Cross Exam Exh. 2; Tr. vol. 10, 695-782. The manual highlighted the need for utilities to give attention to the process and cost of permanently storing CCRs.

> There are serious issues in plant site decommissioning, most of them environmental. The disposal of many years of waste products – ash, water, oils, chemicals – and the removal of asbestos, PCBs, lead products, etc., requires both an understanding of the extent of the contaminations as well as the best methods of removing and disposing of the substances.
>
> . . .
>
> Closure of surface impoundments and landfills probably will be the most expensive tasks undertaken during a decommissioning project.
>
> . . .
>
> Closure of most surface impoundments will require drainage, placement of an impermeable cap, and topping with soil and a vegetative cover. . . . The caps for the impoundments will require continued maintenance to maintain the site contours, vegetative cover and drainage. Some impoundments will require the installation and monitoring of groundwater wells. The waste in

> other surface impoundments may be excavated for disposal offsite, and the impoundment backfilled with clean material.

Tr. vol. 10, 704, 722, 724.

The EPRI handbook described three case studies on plant decommissioning, including the estimated or actual costs incurred. One of the studies was Georgia Power Company's Arkwright Plant. The Arkwright plant was retired in 2002, and the final site cleanup was expected to be completed in 2006. The study reported that the costs for closure of CCR surface impoundments at the Arkwright plant were estimated to be $10,700,000, or about 56.3% of total decommissioning costs net of salvage recovery. *Id.* at 753. Another of the studies was the TVA's Watts Barr plant, which was retired in 2000. The cost for closure and remediation of dry ash units and surface impoundments was estimated to be $9 million, with the total decommissioning cost estimated at $17 million to $25 million. *Id.* at. 754. Notably, the 2004 EPRI Decommissioning Manual preceded the adoption of the CCR Rule by a decade. It is evidence of industry understanding and best practices at a time well before regulatory requirements were in place. The Commission notes that this Manual was issued roughly contemporaneously with the Company's abandonment of the surface impoundments at Possum Point in 2003 when the plant was converted from coal to natural gas. The Company took none of the actions recommended and discussed in the Manual when it ceased use of the Possum Point impoundments.

Challenging prudence requires a detailed and fact-intensive analysis. Imprudence is established by evidence: (1) identifying specific and discrete instances of imprudence; (2) demonstrating the existence of prudent alternatives; and (3) quantifying the effects by calculating imprudently incurred costs. Harris Order, at 15. In the instant proceeding, while the evidence demonstrates a difference of opinion or dispute as to whether certain Company actions, omissions or decisions were prudent, there is no dispute among the parties as to whether any CCR Costs were imprudently incurred.

More specifically, no party presented evidence to attempt to quantify which, if any, of the CCR Costs might have been avoided if DENC had used a different approach to managing its CCRs at some point during the last several decades. Indeed, it would be very difficult to go back and recreate the timing and cost of such different approaches. For example, one could argue that DENC should have converted all of its coal-fired plants to dry ash handling at least at some time during the 1990s. However, to quantify the costs and benefits of this strategy would require establishing, with some level of certainty, the costs that DENC would have incurred for such conversions, and the savings in present CCR remediation costs that would have resulted from such conversions. In addition, DENC could have been entitled to recover those conversion costs, plus a return on its increased rate base, from its ratepayers over the past several decades. On the present record, the Commission has no substantial evidence on which to make such determinations.

Thus, based on the foregoing, the Commission concludes that none of the CCR Costs incurred by the Company between July 1, 2016 through June 30, 2019 shall be disallowed on the basis of having been imprudently incurred. Put another way, based on the evidence in the record in the instant proceeding, the Commission concludes that the CCR Costs were prudently incurred.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 53-55

The evidence in support of these findings of fact and conclusions is found in the testimony of DENC witnesses Williams and McLeod, and Public Staff witnesses Lucas and Maness.

Return on the Unamortized Balance

With respect to whether DENC should be allowed to earn a return on the unamortized balance of the CCR costs during the amortization period, DENC takes the position that the Company is entitled to a full recovery of its CCR Costs, in addition to a return on the unamortized balance while the costs are being amortized. The Public Staff's equitable sharing is achieved, in part, by not allowing a return on the unamortized balance while the costs are being amortized. The AGO takes the position that the Company is not entitled to a return as the costs do not constitute property used and useful in providing utility service.

In analyzing whether DENC should be allowed to earn a return on the unamortized balance of the CCR costs during the amortization period, the Commission finds instructive the cases addressing environmental remediation costs associated with manufactured gas plant and cancellation costs associated with nuclear generating facilities. In Docket No. G-5, Sub 327, Public Service Company of North Carolina, Inc. (PSNC) sought recovery of costs incurred for remediating environmental impacts identified at manufactured natural gas plants (MGPs). Before piped natural gas became available in the 1950s, gas was commonly manufactured by a process that involved the heating of coal in a reduced-oxygen environment. The plants in question in this particular proceeding had been constructed from the mid-1800s to the early- 1900s. The MGPs were taken out of service in the 1950s. By-products of the gas manufacturing process included sulfur, hydrogen sulfide, iron cyanide, light oils, tar, water and coke. These by-products were disposed of consistent with the law applicable at the time but had become the subject of environmental law and regulation. The anticipated remediation costs were estimated to be substantial. The Commission concluded that it was appropriate to allow PSNC to recover its prudently incurred MCP environmental clean-up costs as reasonable operating expenses amortized over a period of years. The Commission did not allow PSNC to earn a return on unamortized balance. The Commission concluded

> that the proper balance between ratepayer and shareholder interests is achieved by amortizing the prudently incurred costs to O&M expenses in general rate cases but denying the Company any recover from ratepayers

> of the carrying costs on the deferred and the unamortized MGP clean-up cost balances.

MGP Order at 23. The Commission reasoned that its approach to ratemaking treatment (which also included rejecting the utility's proposed annual tracker mechanism) gave PSNC an incentive to minimize clean-up costs and to pursue contributions from third parties where appropriate. Finally, looking ahead and anticipating extensive future clean-up costs for MGP liabilities, the Commission reasoned that an appropriate amortization period could be determined in each future rate case proceeding, depending on the magnitude of the costs incurred.

In Docket No. E-22, Sub 273, DENC's 1983 rate case, DENC sought recovery of the abandonment costs of North Anna Units 3 and 4 and Surry Units 3 and 4. The Commission found that DENC's decisions to cancel these nuclear units were reasonable and prudent and that DENC should be allowed to recover its costs up to the point of abandonment. Further, the Commission found that the loss was fairly allocated between DENC and its ratepayers through amortization and not allowing a return on the unamortized balance during the amortization period. The Commission reasoned that:

> [i]t would be inequitable to place the entire loss of expenditures that were prudent when made on the utility. Thus, amortization should be allowed. However, on the other hand, the ratepayer must not bear the entire risk of the Company's investment. A middle ground must be found on which the Company bears some of the risk of abandonment and the ratepayer is protected from unreasonably high rates.

Order Granting Partial Increase in Rates, *Application of Virginia Electric and Power Company for Authority to Adjust and Increase Its Electric Rates and* Charges, No. E-22, Sub 273, 73 N.C.U.C. Orders & Decisions 343, 355 (Dec. 5, 1983) (Anna/Surry Order).

Most recently, this same principle was applied by the Commission in denying DEC a return on the costs of its abandoned Lee nuclear plant. That order included a discussion of numerous similar decisions by the Commission during the last several decades. DEC Sub 1146 Order at 160-63.

As the foregoing decisions by the Commission demonstrate, there is a well-established history of allocating prudently incurred costs, specifically in the context of extraordinary, large costs such as environmental clean-up and plant cancellation, between ratepayers and shareholders in order to strike a fair and reasonable balance. The Commission concludes that in the present case, fairness dictates this same treatment.

DENC's CCR Costs were prudently incurred, thus, it would be inequitable to place the entirety of CCR Costs on DENC's shareholders. However, neither should ratepayers bear the entire risk, and the rate impact, associated with DENC's CCR liabilities.

A number of material facts in evidence call into question the prudence of DENC's actions and inaction and the risks accepted by DENC management at several of its CCR sites. For example, see the discussion of the Possum Point CCR site supra, and the pertinent portions of the industry and government documents previously discussed, such as the 1982 *EPRI Manual for Upgrading Existing Disposal Facilities* and the 1988 EPA Report to Congress entitled *Wastes from the Combustion of Coal by Electric Utility Power Plants*. Moreover, as was the case in the context of the MGP cases and the cancelled nuclear plant cases, the total costs incurred is significant (approximately $377 million on a system level approximately $22 million on a North Carolina retail level), which amounts to approximately $179 per North Carolina retail customer, or $60 per year per North Carolina retail customer, assuming the unamortized balance is not included in rate base. Additionally, allocating all of the CCR Costs to ratepayers violates the matching principle and raises intergenerational equity concerns. DENC's CCR Costs address many decades' worth of coal-ash waste and the closure of coal ash basins related to electric service provided to customers in the past. Tr. vol. 5, 85-88. In fact, most of DENC's expenditures relate to generating stations that have been retired or converted to natural gas and the ash ponds have been retired for years or decades. *Id.*; Late Filed Exhibit 5 MDM-1. Thus, DENC's present and future ratepayers are being burdened with costs arising from past service. Therefore, as it is so required by N.C.G.S. § 62-133(d), the Commission considers these material facts of record when striking the appropriate balance between shareholder and customer interests to set just and reasonable rates. *State ex rel. Utils. Comm'n. v. Thornburg*, 314 N.C. 509, 511, 334 S.E.2d 772, 773 (1985) (concluding that "[i]n setting rates, the Commission must consider not only those specific indicia of a utility's economic status set out in N.C.G.S. § 62-133(b) but also all other material facts of record, which may have a significant bearing on the determination in the case.").

A fair and reasonable balance is found which requires DENC's shareholders to bear some of the risk of clean-up costs associated with CCR liabilities and protects the ratepayers from unreasonably high rates. The Commission concludes that the Company shall not be entitled to earn a return on the unamortized balance of CCR Costs during the amortization period, in light of: (1) the Commission's obligation to set just and reasonable rates that are fair to both the utility and the ratepayer in accordance with N.C.G.S. § 62-133(a); (2) the Commission's historical treatment of extraordinary, large costs, such as MGP environmental remediation costs and plant cancellation costs; and (3) the Commission's obligation to consider all other material facts of record that will enable it to determine what are just and reasonable rates in accordance with N.C.G.S. § 62-133(d).

The Commission notes that the MGP Order points out that the MGP sites were not "used and useful" in providing gas service to current customers. The Commission made a similar determination in the Anna/Surry Order. In their post-hearing filings, DENC, the Public staff, and AGO have addressed in some detail the question of whether DENC's CCR remediation and waste facility closure work has resulted or will result in property used and useful for serving current and future ratepayers. However, as discussed below, based on the evidence in the record, the Commission need not decide in the instant proceeding whether DENC's CCR Costs at issue in this case have produced property that is or will be used and useful in providing service to present and future ratepayers.

With respect to whether the CCR Costs are entitled to a return under N.C.G.S. § 62-133(b)(1), DENC witness McLeod maintained that they are so entitled, in light of the Commission's decisions in the 2016 DENC Rate Case and the 2018 DEP and DEC rate cases that the CCR expenditures were "used and useful" because they were recorded by the utilities in the working capital section of the rate base and were investor-furnished rather than ratepayer-furnished funds. *Id.* at 679. The Commission is not persuaded by this position.

North Carolina General Statutes § 62-133(b)(1) allows the recovery of a return on investment in property and plant that is used and useful in providing utility service. The Commission takes no issue with the Company's decision to establish an ARO to recognize its CCR obligations or its labeling of CCR costs as working capital for accounting purposes. However, these accounting practices do not *ipso facto* transform these costs into expenditures for "property used and useful" under the Act. Further, the Supreme Court's holding on working capital made in *State ex rel. Utilities Commission v. Virginia Electric & Power Co.*, 285 N.C. 398, 206 S.E.2d 283 (1974) (*VEPCO*), did not change the used and useful requirement of N.C.G.S. § 62-133(b)(1). The Company advances a reading of *VEPCO* that would, if accepted, obliterate any distinction between investment in property used and useful in providing service to customers and expenditures for ordinary operation and maintenance. As the Company reads that case, all amounts expended by the Company for whatever purpose and to whatever end constitute "working capital" eligible to earn a return, unless perhaps those amounts are funded from prepayments made by customers. This argument ignores the important portion of the holding in *VEPCO* that affirmed the Commission's $60,783 deduction from working capital in recognition of the Company's rates that included an amount for payment of the Company's federal income taxes. The Company protested that this deduction was improper because the Company's tax deferral account showed a negative amount for federal income taxes during the test period. In upholding the Commission's position, the Court stated:

> The absence of an actual tax liability during the test period does not alter the fact that Vepco's North Carolina customers have paid to it rates which included enough to cover anticipated Federal income taxes. The question here is not how much, if anything, Vepco must pay to the United States. The questions are how large a fund Vepco has collected from its customers with which to pay taxes and how long it has had the use of such fund. Having had the use of funds so collected, it is not entitled to ignore its use thereof when computing its working capital requirement. We see no error in the order of the Commission in this respect.

VEPCO, at 416-17.

Also undermining DENC's position in the present case is the Company's own evidence showing its calculation of its requirement for "cash working capital." NCUC Form E-1, Item No. 14. None of the expenditures made to address coal ash are included in the Company's analysis of its working capital needs. As a result, the Company's contention that it has used shareholder provided working capital to pay for expenditures to comply with the CCR Rule and close its coal ash facilities is nothing more than an *ipse dixit* entitled to no evidentiary weight.[23]

Additionally, at the hearing witness McLeod confirmed that the vast majority of the CCR expenditures were for services and labor and would have been charged to operation and maintenance expenses in the absence of GAAP ARO accounting requirements. Tr. vol. 7, Official Exhibits, Public Staff McLeod Cross-Examination Exh. 1. He also confirmed that roughly 98% of the CCR costs incurred during the Deferral Period would have been booked as operation and maintenance expenses but for GAAP accounting requirements. Tr. vol. 7, 9-11; *see also* Tr. vol. 7, Official Exhibits, Public Staff Paul McLeod Cross-Examination Exh. 2. Further, he agreed that $209 million of the total $390.4 million total CCR expenditures were incurred at coal plants that had been decommissioned. Tr. vol. 7, Official Exhibits, Public Staff Paul McLeod Cross-Examination Exh. 2. Thus, it is very likely that had the CCR Costs been incurred during the test year, they would have been recovered as operating expenses on which no return would have been earned.

Giving weight to all sections of N.C.G.S. § 62-133 when construing the language of any individual section of the statute, as the North Carolina Supreme Court has indicated the Commission must do, the Commission determines that just and reasonable rates are achieved, based on the evidence in the record in this proceeding, only when the unamortized balance of CCR Costs are not allowed to earn a return. *Utilities Comm'n v. Duke Power Co.*, 305 N.C. 1, 18, 287 S.E.2d 786, 796 (1982). Accordingly, based on the record as a whole, the Commission concludes that it is appropriate to treat the CCR Costs as deferred operating expenses and not as costs of property used and useful within the meaning and scope of N.C.G.S. § 62-133(b) and to not allow a return on the unamortized balance of the CCR Costs.

Amortization Period

With regard to the amortization period over which the CCR costs should be recovered, DENC submitted that an amortization period of five years would be reasonable and appropriate. The Public Staff proposed an amortization period of eighteen years as part of its equitable sharing recommendation. The Commission has declined to adopt the Public Staff's equitable sharing recommendation. However, the Commission has determined that a reasonable balancing between shareholders and ratepayers of the

[23] On this issue it is well to keep in mind Justice, later Chief Justice, Barnhill's observation in *State ex rel. Utilities Commission v. North Carolina*, 239 N.C. 333, 348, 80 S.E.2d 133, 143 (1954), that when "it is made to appear [the utility] has on hand continuously a large sum of money it is using as working capital and to pay current bills for materials and supplies, that is a fact which must be taken into consideration. And if the fund on hand is sufficient, no additional sum should be allowed at the expense of the public."

costs of CCR remediation is just and reasonable and must establish an appropriate amortization period based on the evidence in the record in this proceeding. The Commission concludes that DENC's proposed five-year amortization period does not achieve a fair balance in light of the evidence in the record, the magnitude and the nature of the costs involved and the rate impact to customers. The Commission concludes that based on the evidence in the record, the magnitude and nature of the costs involved and the rate impact to customers as testified to by the Public Staff, a ten-year amortization period strikes the more appropriate and fairer balance. This decision is consistent with the Commission's historical treatment of major plant cancellations. *See* Anna/Surry Order at 355 (noting that [t]his Commission has consistently used a write-off period of 10 or fewer years for all major plant cancellations).

Financing Costs During Deferral Period

The Commission concludes that allowing the company to recover the financing costs incurred during the Deferral Period and up to the effective date of the new rates approved pursuant to this Order, calculated at the Company's previously authorized weighted average cost of capital, is reasonable based on the facts of record in this proceeding.

The decision to allow the Company to recover its financing costs incurred during the Deferral Period is made independently of the Commission's decision regarding the Company's right to earn a return on the unamortized balance of the CCR Costs during the amortization period. It is within the Commission's authority to approve a regulatory asset to defer for future recovery expenses that were incurred in the past and even to provide for a return on those deferred expenditures, such as by providing for carrying costs. In compliance with this Commission's authorization in the 2016 DENC Rate Case, the CCR Costs have been deferred to permit appropriate ratemaking treatment in this general rate case. The ratemaking treatment of the CCR Costs has been established in accordance with N.C.G.S. § 62-133 and applicable legal principles, as previously discussed in this Order. The Commission concludes that, separate and distinct from the ratemaking treatment afforded the CCR Costs, allowing the Company to recover its financing costs incurred during the Deferral Period is appropriate based on the record of the instant proceeding.

Specifically, the Public Staff did not oppose the Company's recovering the financing costs incurred during the Deferral Period. Further, the Commission observes that such a return may reduce the incentive for the Company to apply for rate increases more frequently to avoid regulatory lag. While recovering financing costs incurred during the Deferral Period does not help with the Company's short-term cash flow, it means the Company ultimately does not experience lost financing costs if it delays a new rate case.

Public Staff's Equitable Sharing Recommendation

The Public Staff proposed allocating the Company's CCR Costs between shareholders and customers based on the concept of "equitable sharing."[24] The Public Staff takes the position that conducting a thorough analysis of the reasonableness and prudence of all actions and expenditures over several decades would be difficult, if not impossible, given the passage of time, the speculative nature of estimating historic environmental remediation costs, and the Company's lack of historical records and documents related to CCR liabilities. Therefore, the Public Staff's proposed equitable sharing is based on a weighing of the equities, as opposed to application of the ratemaking framework prescribed by N.C.G.S § 62-133. After considering the equities, the Public Staff concluded that, inasmuch as it determined DENC was "culpable" or accountable for taking the actions that have led to the current CCR Costs, DENC's shareholders should bear more of the burden of the CCR Costs than the customers, who relied and depended on the Company's safe and appropriate handling of CCRs. However, the Public Staff determined that the customers should also share in the burden of CCR Costs, but to a lesser degree, because they have benefitted from the past decades of coal-fired generation and past least-cost coal ash disposal methods (such as CCR surface impoundments) in the form of the lower electric rates.

The Commission understands the Public Staff's position on the challenges, in the context of the Company's CCR-related expenditures, to performing a review of the reasonableness and prudence of those expenditures. Nevertheless, the Commission has declined to follow the Public Staff's equitable sharing recommendation, and has instead, as discussed hereinabove, reached its decision based on the evidence in the record and adherence to the ratemaking framework prescribed by N.C.G.S. § 62-133, which requires an analysis of the reasonableness and prudence of the expenditures in question. Because the record in this proceeding lacks an evidentiary basis on which to find that any of the CCR Costs were imprudent, the Commission declines to disallow the recovery of any of the CCR Costs, to the extent the Public Staff's approach could be interpreted to amount to a disallowance. In addition, contrary to the Public Staff's equitable sharing approach, in which the allocation of costs between customers and shareholders is predetermined (i.e., 60/40) based on a theory of "culpability" and the ratemaking treatment is then selected to achieve that predetermined allocation, the Commission has reached its determination on the recovery and ratemaking treatment of CCR Costs by applying the provisions of N.C.G.S. § 62-133, which involves an examination of

[24] The historical decisions of the Commission dealing with ratemaking treatment of extraordinary and significant costs, such as plant cancellation costs and MGP environmental remediation costs, do not involve or reference an "equitable sharing" approach but rather involve the application of the rate-setting provisions of the Act to the facts of the case. Thus, the approach recommended by the Public Staff in this proceeding, as well as the most recent DEC and DEP general rate cases, appears to be novel.

reasonableness and prudence of the CCR Costs, to the evidence of record in this proceeding in a manner that is consistent with historical decisions of the Commission.

Compounding During Deferral Period

The Commission concludes the annual compounding approach recommended by the Public Staff and agreed to by DENC in its rebuttal testimony is more reasonable than monthly compounding for the return during the Deferral Period that it is reasonable, based on the evidence in the record in this proceeding, for DENC to recover its financing costs incurred during the Deferral Period. Further, the Commission concludes that the annual compounding approach recommended by the Public Staff and agreed to by DENC in its rebuttal testimony is more reasonable than monthly compounding for calculating financing costs during the Deferral Period. Annual compounding, as explained by Public Staff witness Maness, results in the Company recovering financing costs that correspond to the weighted average cost of capital approved in the Company's last general rate case, whereas monthly compounding would produce a higher amount of return.

Maintenance of Environmental Records

Finally, due to the Company's failure to retain or produce adequate records regarding its CCR handling and storage, the Commission finds good cause to require the Company to maintain complete records of all environmental management activity and test results as they pertain to its coal ash management program, and to make such records available to the Public Staff and the Commission upon request. Further, data collected by the Company in the course of its environmental regulatory compliance, including groundwater monitoring data and analytics as well as other environmental compliance data, should be provided to the Public Staff and the Commission in the format that is reasonably requested by the Public Staff and the Commission.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 56-58

The evidence supporting these findings of fact and conclusions is contained in DENC Late-Filed Exhibits 3 and 5, DENC's 2011 and 2016 depreciation studies, and the records of DENC's last three general rate cases, Docket Nos. E-22, Subs 459, 479, and 532.

As previously discussed, one of the fundamentals of cost-based ratemaking as it has developed in this state is that the full cost of providing utility service should be recovered, as near as may be possible, from rates in effect in the period in which service is provided. One objective of this useful and important "matching principle" is to encourage customers to make efficient and cost-effective use of utility services by enabling them to see and appreciate the full cost of the service provided, even when some of the expenditures required to provide the service may be incurred or made by the utility at some time either before or after the service is actually consumed. A companion objective is to avoid cost-shifting and subsidies among different generations of customers who consume service during different time periods. Achieving these objectives is complicated by the fact that many expenditures by a utility company, especially construction of capital intensive facilities to generate, transmit and distribute electricity, are lumpy; that is, a large expenditure may be made in a very short period of time, but the investment thus made will enable the utility to provide service to customers over many years. The well-accepted method for smoothing out this lumpiness and enabling the costs of large scale capital investments to be recovered from all generations of customers who will benefit from and receive service from those facilities is by allowing the utility to include in its rates a regular periodic allowance for use and consumption of the investment, i.e., an allowance for depreciation. Through depreciation allowance, recovery of the costs of making a large investment are spread over many ratepayers, rather than being borne only by that group of ratepayers taking service during the time the expenditure is actually made.

In the usual case costs associated with the retirement or decommissioning of a long-lived asset are, in accord with the matching principle, included as part of the periodic allowance for depreciation that is related to that asset. This marks a recognition of the fact that while significant costs are incurred to construct or to acquire an asset, it may also be that significant costs will be incurred when the asset reaches the end of its useful life, including such things as costs to dismantle, decommission, remove, secure, or dispose of the asset. Failure to anticipate these end-of-life costs and make provision for them in the periodic allowance for depreciation distorts the true cost of providing service to those customers who take service during the asset's useful life and shifts a portion of those costs to the unlucky customers who happen to take service at a time when the asset is retired. *Generally see*, *State ex rel. Utilities Commission v. Edmisten*, 291 N.C. 451, 232 S.E.2d 184 (1977) (*Edmisten III*). Such is the case here with respect to the costs of closing waste coal ash management units when they are no longer receiving ash. These end-of-life costs are referred to as either "interim" or "terminal" net salvage values and for purposes of depreciation they are treated the same as the initial cost to acquire or construct the asset. They may be positive, if the asset is expected to yield a positive return when it is retired, or they may be negative, if the cost of decommissioning the asset is expected to exceed any value from salvage.

In the present case, however, the Company's request to include in its present and future rates the costs of final handling and disposal of CCRs produced from the burning of coal over many decades is a departure from the matching principle. In response to a question from the Commission, the Company reported that it had not included in its allowances for depreciation any amount toward the costs now being incurred to close the waste ash management units at its coal-fired generating plants. DENC Late-Filed Exhibit No. 3. The Company stated:

> This is appropriate as the Company has not yet identified the nature and timing of such [closure] activities and therefore the projected costs have not been reasonably known and measurable. This treatment is assessed by the Company's accountants, depreciation consultant and generation management as part of preparing each depreciation study.

It is clear from the Company's response and from the record of this case and the Company's prior rate cases that at no time prior to the present rate case – not as part of its depreciation studies prepared in 2011, or in 2016, and not as part of its general rate case applications filed in 2009, 2012 and 2016 – has the Company sought to recover in its rates any amount for costs of final closure of its waste ash management facilities. *See* Docket Nos. E-22, Subs 459 and 479 (updated 2011 depreciation study filed in Docket No. E-22, Sub 493 on April 1, 2013); and Sub 532 (updated 2016 depreciation study filed in Docket No. E-22, Sub 562 on August 21, 2019). The Company's explanation of its failure to consider or include costs of closure for waste coal ash facilities in calculating an allowance for depreciation is not persuasive for a number of reasons.

Industry understanding of the need to anticipate significant costs for final closure of waste coal ash management facilities is not something that developed only recently. On this topic Company witness Williams acknowledged that he was familiar with the 2004 report prepared by EPRI titled "Decommissioning Handbook for Coal-Fired Power Plants" (Decommissioning Manual). Tr. vol. 10, Official Exhibits, DEC Rate Case, Docket No. E-7, Sub 1146, AGO McManeus Cross-Exam Exh. 2, at 699-782. However, he dismissed the report as merely a series of case studies, ignoring the report's general findings and conclusions, including this clear and unambiguous admonition:

> [C]losure of most surface impoundments will require drainage, placement of an impermeable cap, and topping with soil and a vegetative cover. . . . The caps for the impoundments will require continued maintenance to maintain the site contours, vegetative cover and drainage. Some impoundments will require the installation and monitoring of groundwater wells. The waste in other surface impoundments may be excavated for disposal offsite, and the impoundment backfilled with clean material.

Id. at 724.

Discussing the various tasks and costs that could be expected as part of the retirement of a plant, the manual later observed that "[c]losure of surface impoundments and landfills probably will be the most expensive tasks undertaken during a decommissioning project." *Id.* at 722. Nothing in the 2004 EPRI Decommissioning Manual is presented as novel, unexpected, groundbreaking, or beyond the scope of sound industry practice as it was understood in 2004. It is notable that this report precedes by more than a decade the adoption of the CCR Rule and was issued several years before the EPA commenced rulemaking on the subject of disposal of coal ash wastes. The case studies presented in the report make clear that the costs of closure of coal ash disposal facilities could likely range well into the tens of millions of dollars.

We know now that the costs that DENC is likely to incur will greatly exceed even the amounts revealed in the 2004 case studies reviewed in the EPRI Decommissioning Manual, and the Company apparently believes that the difficulty in making precise estimates of final closure costs absolves it of responsibility for making the effort to do so at all. This is not acceptable. As the Company itself noted in its response to the

Commission's question, depreciation studies and requested allowances for depreciation are periodically reviewed and updated to include the latest information and to make adjustments where necessary in light of such new information. This was precisely the purpose of the Company's regular review and updating of its depreciation studies in 2006, 2011 and 2016. Further, this is quite similar to the requirement for establishing an Asset Retirement Obligation (ARO) when the Company has a known but not perfectly quantifiable risk associated with future retirement of a long-life asset. *See* Order Allowing Utilization of Certain Accounts, *Request by Virginia Electric and Power Company, d/b/a Dominion North Carolina Power*, No. E-22, Sub 420 (N.C.U.C. Aug. 6, 2004) (approving DENC's use of ARO accounting for certain long-life assets in compliance with Statement of Financial Accounting Standards No. 143).

This is not a case where the Company simply made inaccurate projections of the necessary allowance for net salvage to be included in depreciation allowance; instead, with respect to that portion of net salvage value attributable to the costs of remediating and closing coal ash waste management facilities it failed to engage in the exercise at all.

Recovery of net salvage in depreciation, including costs of removal, decommissioning, and closure, has been endorsed by the Commission, and the Company cannot complain that there has been no regulatory guidance on the subject.

Pertinent here is the Commission's decision in Order Granting Partial Rate Increase, *Application by Aqua North Carolina, Inc., for Authority to Increase Rates for Water and Sewer Utility Service in All of Its Service Areas in North Carolina*, No. W-218, Sub 319 (N.C.U.C. Nov. 3, 2011) (Aqua Order). In that proceeding, Aqua and the Public Staff disagreed as to the propriety of including in depreciation expense, and thus in rates, amounts for terminal net salvage value that would reflect and incorporate costs of removal. The Company's witnesses pointed out that including these amounts in current depreciation expense would properly assign a portion of expected future expenses to those customers who were currently receiving the benefit of the utility plant while it was still in service. The Public Staff contended that such a practice would improperly require present customers to pay for future costs that might or might not actually be incurred or might be different in amount at the time actually incurred. As to this difference of opinion, the Commission noted the applicant's testimony in the following summary:

> Witness Spanos advocated utilizing the net salvage percentage for depreciation accrual rates consistently with the new practice[25] of recording the cost of removal as the most appropriate methodology. Therefore, according to witness Spanos, the cost of removal for each project will be charged to accumulated depreciation at the same time the Company accrues for the net salvage value in rates. Witness Spanos asserted that

[25] Elsewhere in the Aqua Order it is made clear that "new practice" means "new for this applicant," not new for the accounting profession. Prior to Aqua's 2011 rate case, Aqua North Carolina had not been computing net salvage values as part of depreciation expense.

> this consistent treatment properly assigns costs to those ratepayers receiving benefit for the asset while in service; this applies to all accounts.

Aqua Order at 70. Aqua witness Spanos further explained that the entire cost of the asset, including costs of removal, should be recovered over the useful life of the asset and not recovered from customers after the asset's useful life had ended. *Id.*

In its order the Commission disagreed with the Public Staff's position and instead sided with the Company and its depreciation expert, witness Spanos, finding that

> utilizing the net salvage value percentage for depreciation accrual rates consistently with the new practice of recording the cost of removal is the most appropriate methodology. The Commission understands that using this methodology, the cost of removal for each project will be charged to accumulated depreciation at the same time the Company accrues for the net salvage in rates. *This treatment properly assigns costs to those ratepayers receiving benefit for the asset while in service and properly applies to all accounts.*

Id. at 72 (emphasis added).

In addition, the Commission notes that at least one of DENC's peer utilities regulated by the Commission, Duke Energy Progress, did understand the need to address costs of closure of coal ash impoundments in depreciation allowances, although the amount to be recovered by DEP through depreciation proved inadequate to cover its actual final costs of closure. *See* DEP Rate Case Order, at 42, 138.

In the quote above from DENC Late-Filed Exhibit No. 3, the Company stated that it has relied, in part, on its depreciation consultant for the position it has taken. The Company's expert on depreciation is the firm of Gannett Fleming, Inc., and more specifically Mr. John J. Spanos of that firm. Mr. Spanos signed the cover letters accompanying DENC's 2011 and 2016 depreciation studies as Senior Vice President, Valuation and Rate Division. *See* Docket Nos. E-22, Subs 459 and 479 (updated 2011 depreciation study filed in Docket No. E-22, Sub 493 on April 1, 2013); and Sub 532 (updated 2016 depreciation study filed in Docket No. E-22, Sub 562 on August 21, 2019).

Mr. Spanos has frequently appeared before the Commission and is well-recognized in his field. Although he provided no testimony in the present case, on the point now at issue the Commission finds it appropriate to take judicial notice of testimony he provided in 2015 before the South Dakota Public Utilities Commission where he testified on behalf of Black Hills Power, Inc., an electric utility regulated by the South Dakota Commission.[26] This testimony was filed on January 15, 2015, before the date of the Company's most recent depreciation study for its 2016 North Carolina rate case filing.

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[26] Rebuttal Testimony and Exhibit of John J. Spanos, *Application of Black Hills Power, Inc., for Authority to Increase Rates in South Dakota*, No. EL14-026 (S.D.P.U.C. Apr. 17, 2015), *reh'g denied*,

In the Black Hills Power case an intervenor objected to Mr. Spanos' inclusion of the costs of decommissioning (net salvage value) in the proposed depreciation rates for the utility's coal-fired generating plants. The intervenor's position was that such costs should be recovered only at and after the time of decommissioning when they could be known and measured with certainty. Rejecting that view, Mr. Spanos testified:

> The primary depreciation issue in this case is whether the Company will experience terminal net salvage for their power plants when they are eventually retired. Experience now shows that not only will power plants be retired, but there are significant costs upon retirement related not only to the dismantlement of the plant itself, but also to the remediation of features of the site such as ash ponds. Since these costs are likely to be incurred, intergenerational equity and depreciation authorities require that they be included in depreciation and recovered over the service lives of the plants.

Pre-Filed Rebuttal Testimony of John J. Spanos, *Application of Black Hills Power, Inc., for Authority to Increase Rates*, No. EL14-026, at 4 (S.D.P.U.C. Apr. 17, 2015).

Asked to provide examples of the types of costs to which he was referring, Mr. Spanos testified:

> Duke Energy plans to decommission a number of sites in the Carolinas, and activities related to the retirement of these sites include asbestos removal, demolition and the closure of ash ponds. Dominion Virginia Power is in the process of decommissioning coal units at its Chesapeake Energy Center, North Branch and Yorktown sites.

Id. at 8 (similar testimony given at pp. 9-11).

Buttressing his position by referring to other published authorities, he noted:

> The [Uniform System of Accounts] prescribes that net salvage costs should be accrued over the course of an asset's service life (i.e., recognized in each period in which the asset provides service) in a systematic and rational manner. *Net salvage costs should not be recognized in the period in which any salvage-related costs are paid and should not be recovered after these costs are incurred.*

Id. at 15 (emphasis added).

Finally, responding to the intervenor's position that net salvage and cost of removal should remain a fixed value over the entire life of an asset and should not be updated or

(S.D.P.U.C. May 29, 2015), https://puc.sd.gov/commission/dockets/electric/2014/EL14-026/rebuttalbhp/spanostestimony.pdf adjusted, Mr. Spanos testified that not only was period reassessment and updating proper but that it was in fact required as new information became available. *Id.* at 17-18.

Mr. Spanos' testimony before the South Dakota Public Utilities Commission, and his testimony before this Commission in Docket No. W-218, Sub 319 referred to earlier, is a clear rebuke to the Company's position in this case. His views are not idiosyncratic; they are fully in line with widely accepted authority. Mr. Spanos provided the following from the 1996 NARUC manual entitled *Public Utility Depreciation Practices*:

> Historically, most regulatory commissions have required that both gross salvage and cost of removal be reflected in depreciation rates. The theory behind this requirement is that since most physical plant placed in service will have some residual value at the time of retirement, the original cost recovered through depreciation should be reduced by that amount. Closely associated with this reasoning is the accounting principle that revenues be matched with costs and the regulatory principle that utility customers who benefit from the consumption of plant pay for the cost of that plant, no more, no less. The application of the latter principle also requires that the estimated cost of removal of plant be recovered over its life.

NARUC, *Public Utility Depreciation Practices* 157 (1996).

In addition, Mr. Spanos quoted the following from the 1994 edition of *Depreciation Systems*.

> The matching principle specifies that all costs incurred to produce a service should be matched against the revenue produced. Estimated future costs of retiring an asset currently in service must be accrued and allocated as part of the current expenses.

W. C. Fitch and Frank K. Wolf, *Depreciation Systems* 7 (1994).

How, then, does this principle apply in this case to the recovery of the costs for closure of DENC's waste coal ash management facilities? Recognizing the inherent difficulty in accurately forecasting expenditures that will materialize only many years into the future and that must also accommodate evolving standards of industry practice and regulatory requirements, the Commission concludes that it would be unfair to deny recovery altogether based solely on the fact that the Company made no attempt to collect the costs from earlier generations of ratepayers. But by the same token, complete recovery at the expense of current and future ratepayers cannot be squared with the bedrock principles just reviewed. In the end, the Commission concludes that the balancing that will be achieved by a ten-year amortization of DENC's CCR costs without a return is further supported by the failure of DENC to properly account for the full decommissioning costs of its coal-fired power plants and to collect its best reasonable estimate of those costs as part of depreciation allowance, adjusted from time to time as new information was acquired. In addition, the Commission finds good cause to direct that in DENC's next update of its depreciation study it should account for its projected CCR remediation and closure costs in the decommissioning expenses for its coal-fired power plants.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 59-62

The evidence supporting these findings of fact and conclusions is contained in the direct testimony of Public Staff witness Lucas, and the Post-Hearing Exhibits of DENC.

In his testimony, witness Lucas explained that the Public Staff investigated whether the Company has environmental or general liability insurance that would provide coverage for its CCR-related costs, and that the Public Staff reviewed notices, claims, and related documents sent by the Company to insurers that relate to CCR. Tr. vol. 6, 196. Based on the Public Staff's review, witness Lucas recommended that the Commission monitor the Company's existing and potential insurance claims. He stated that if any insurance proceeds are ultimately received or recovered, the Commission should require that the Company place all such proceeds into a regulatory liability account to either be disbursed back to ratepayers or to offset the costs to ratepayers of the Company's CCR-related costs. *Id.* at 197.

DENC's Confidential Post-Hearing Exhibit No. 2, filed herein on October 23, 2019, includes the details of the potential insurance policy recoveries related to possible CCR liabilities of DENC.

Discussion and Conclusions

To the extent that ratepayers are required to pay the costs of CCR remediation, and DENC's insurance policies cover some of those costs, ratepayers should receive all or a portion of the insurance proceeds. In that regard, DENC is representing the interests of its ratepayers in pursuing the insurance claims. Therefore, the Commission finds it appropriate to hold DENC to the same standard of care that DENC is required to exercise in providing electric service. That standard is one of reasonableness and prudence. In subsequent proceedings, if the parties or the Commission raise meritorious issues about DENC's representation of the interests of ratepayers in the insurance claims, DENC shall bear the burden of proving that it exercised reasonable care and made prudent efforts to obtain the maximum recovery from the insurance claims.

Further, the Commission concludes that DENC should be required to place all insurance proceeds received or recovered by DENC in the insurance claims in a regulatory liability account and hold such proceeds until the Commission enters an order directing DENC as to the appropriate disbursement of the proceeds. In addition, the regulatory liability account shall accrue a carrying charge at the overall rate of return authorized for DENC in this Order.

Finally, based on the risk sharing allocation of CCR costs adopted by the Commission, DENC is entitled to retain a percentage of the CCR insurance proceeds equal to the above weighted average equity capital financing.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 63

The evidence supporting this finding of fact and these conclusions is contained in the findings and conclusions of the Commission herein pertaining to authorized cost deferrals by DENC.

In the present case, the Commission is approving DENC's post-in-service costs of the Greensville CC and recovery through amortization of a previously deferred portion of DENC's CCR costs. The Commission notes that a deferred cost is not the same as the other cost of service expenses recovered in the Company's non-fuel base rates. A deferred cost is an exception to the general principle that the Company's current cost of service expenses should be recovered as part of the Company's current revenues. When the Commission approves a typical cost of service, such as salaries and depreciation expense, there is a reasonable expectation that the expense will continue at essentially the same level until the Company's next general rate case, at which time it will be reset. On the other hand, when the Commission approves a deferred cost the Commission identifies a specific amount that has already been incurred by the Company, or, in the case of CCR costs, is estimated to be incurred by the Company. In addition, the Commission sets the recovery of the amount over a specific period of time. Further, the Company is directed to record the recovery of the specific amount in a regulatory asset account, rather than a general revenue account. If DENC continues to recover that deferred cost for a longer period of time than the amortization period approved by the Commission that does not mean that DENC is then entitled to convert those deferred costs into general revenue and record them in its general revenue accounts. Rather, the Company should continue to record all amounts recovered as deferred costs in the specific regulatory asset account established for those deferred costs until the Company's next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 64-65

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

Summary of the Evidence

In the Application and initial direct testimony and exhibits, DENC provided evidence supporting an increase of approximately $27 million in its annual non-fuel revenues from its North Carolina retail electric operations. With regard to fuel, in his direct testimony Company witness McLeod testified that the Company annualized fuel clause revenue by applying the current base fuel rate plus Rider A to the annualized and normalized customer usage at June 30, 2019. Witness McLeod also explained that an adjustment was made to fuel clause expense to make fuel clause expense equal to fuel clause revenue, net of the regulatory fee. Tr. vol. 4, 260.

On August 5, 2019, the Company filed supplemental direct testimony and exhibits updating several cost of service adjustments. These updated adjustments decreased the Company's revenue requirement by approximately $2.1 million, for a revised increase in North Carolina retail revenue of $24.9 million, which was reduced again in the Company's additional supplemental testimony filed on September 12, 2019, to $24.2 million.

On August 23, 2019, the Public Staff filed the direct testimony of witness Johnson, presenting her recommended accounting and ratemaking adjustments to the Company's proposed revenue requirement. Accounting for these adjustments, she recommended a decrease in the Company's annual base non-fuel operating revenue of $8,112,000. Witness Johnson also testified that the Public Staff adjusted the fuel clause expense to reflect the base fuel rate and Rider A as set forth in the Additional Supplemental Testimony of DENC witness Haynes and recommended by Public Staff witness Jack Floyd, subject to the outcome of the Company's currently ongoing fuel proceeding in Docket No. E-22, Sub 579. Witness Johnson stated that this adjustment resulted in a decrease of $2.155 million from the fuel expense originally included in the Company's Application. Tr. vol. 6, 39.

On September 17, 2019, the Company and the Public Staff entered into and filed the Public Staff Stipulation. Also on September 17, 2019, the Company filed the testimony of witnesses McLeod, Miller, Hevert, Davis, and Haynes in support of the stipulated revenue increase. These witnesses testified in support of the accounting and ratemaking adjustments agreed upon in the Public Staff Stipulation. They also testified that the Public Staff Stipulation is the result of negotiations between the Stipulating Parties. Also on September 17, 2019, the Public Staff filed the Joint Stipulation testimony of witnesses Johnson and McLawhorn, recommending and supporting the stipulated adjustments to the Company's requested revenue increase while also noting the unresolved issues related to CCRs.

The Public Staff Stipulation, as shown on Settlement Exhibit I, reflects the Company's proposed increase in the revenue requirement of $6.428 million, consisting of an increase of $8.583 million in non-fuel revenues and a decrease of $2.155 million in base fuel revenues, and the Public Staff's proposed increase in the revenue requirement of $2.037 million, consisting of an increase in $4.192 million in non-fuel revenues and a decrease of $2.155 million in base fuel revenues. The difference between the Company's and the Public Staff's proposals in the Public Staff Stipulation result from the unresolved issues identified at Section II.A.i of the Public Staff Stipulation (cost recovery of the Company's CCR costs, the recovery amortization period, and return during the amortization period).

Discussion and Conclusions

As discussed in the body of this Order, the Commission approves the Public Staff Stipulation, with the exception of section VII.A, and makes its individual rulings on the unresolved issues as discussed herein. As the unresolved issues pertaining to CCR cost recovery, and the Commission's decision in this Order on the conversion costs at Chesterfield Units 3 and 4, were not addressed by the Public Staff Stipulation and accompanying testimony and exhibits, the Commission requests that DENC recalculate the required annual revenue requirement consistent with all of the Commission's findings and rulings herein as soon as practicable following the issuance of this Order. The Commission further orders DENC to work with the Public Staff to verify the accuracy of the recalculations. Once the Commission receives this filing, the Commission will work promptly to verify the calculations and will issue an order with final revenue requirement numbers. DENC should provide electronic copies of this filing to the Commission, complete with formulas intact.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 66

The evidence supporting this finding of fact and these conclusions is contained in the verified Application, the testimony and exhibits of the DENC and Public Staff witnesses, the Public Staff Stipulation, and the record as a whole.

Pursuant to N.C.G.S. § 62-133(a), as described earlier, the Commission is required to set rates that are "fair both to the public utilities and to the consumer." In order to strike this balance between the utility and its customers, the Commission must consider, among other factors: (1) the utility's reasonable and prudent cost of property used and useful in providing adequate, safe and reliable service to ratepayers, and (2) a rate of return on the utility's rate base that is both fair to ratepayers and provides an opportunity for the utility through sound management to attract sufficient capital to maintain its financial strength. N.C.G.S. § 62-133(b). DENC's continued operation as a safe, adequate, and reliable source of electric service for its customers is vitally important to DENC's individual customers, as well as to the communities and businesses served by DENC. DENC presented credible and substantial evidence of its need for increased capital investment to, among other things, maintain and increase the reliability of its system and comply with environmental requirements.

For example, DENC witness Mitchell testified that during the last three years, the Company invested $1.3 billion to bring online a total of 1,588 MW of new generation in the Greensville County CC. Witness Mitchell stated that this new generation is cleaner and highly-efficient combined cycle generating capacity that has the potential to create substantial fuel savings due to very favorable current natural gas prices. Witness Mitchell also noted that the Company has invested $132 million to bring on-line three regulated solar facilities totaling 56 MW and between 2019 and 2020 plans to invest approximately $410 million to bring on-line an additional 240 MW of nameplate solar capacity. Witness Mitchell also testified that the Company has received a certificate of public convenience and necessity to construct the 12 MW Coastal Virginia Offshore Wind Project that is expected to come on-line in 2020. Finally, witness Mitchell explained that the Virginia Grid Modernization and Security Act specified that up to 5,000 MW of solar and wind generation facilities constructed by a utility such as the Company are in the public interest and the Company has committed to have approximate 3,000 MW placed in service or under development by the end of 2022. Tr. vol. 6, 171-72.

Witness Mitchell further testified that DENC has spent approximately $268 million on transmission improvements in North Carolina during the last three years. He stated that these improvements support improved reliability of the transmission system and local economic growth. He also testified that the Company plans to invest an additional $200 million in transmission improvements in North Carolina over the next five years. Tr. vol. 6, 173-74.

In addition, witness Mitchell testified that DENC has invested over $29 million in its distribution system in North Carolina during the last three years. He stated that these investments balance the need for reliable service with prudent spending. *Id.*

Witness Mitchell also testified regarding the impact of current and proposed environmental regulations on the Company's operations. He stated that during the last decade electric utilities have been required to address compliance with a suite of new environmental standards adopted by the EPA. He testified that compliance with these standards has directly impacted DENC's operation of its coal-fired generating plants, citing as an example the EPA's Mercury Air Toxics Standards Rule, which led to the retirement of over 900 MW of coal-fired generating capacity. Witness Mitchell also stated that the enactment of the CCR Rule in April 2015 created a legal obligation for the Company to retrofit or close all of its inactive and existing ash ponds, as well as perform required monitoring, corrective action, and post-closure activities as necessary. *Id.* at 170-76.

Moreover, witness Mitchell testified that DENC plans to invest $11.1 billion over the next three years for generation, transmission, and distribution investments in order for the Company to continue to fulfill its obligations of providing reliable, cost-effective service in an environmentally responsible manner for DENC's customers. *Id.* at 177.

These are representative examples of the capital investments that have been made and are planned to be made by DENC in order to continue providing safe, reliable, and efficient electric service to its customers. Based on all of the evidence, the Commission finds and concludes that the rates established herein strike the appropriate balance between the interests of DENC's customers in receiving safe, reliable, and efficient electric service at the lowest possible rates, and the interests of DENC in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the Commission concludes that the rates established by this Order are just and reasonable under the requirements of N.C.G.S. § 62-130, et seq.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation filed by DENC and the Public Staff is hereby approved, with the exception of Section VII.A;

2. That DENC shall consult with the Public Staff in accordance with the directive in the body of this Order, and shall remove from its revenue requirement and rate base all North Carolina retail jurisdictional costs and effects arising from the wet to dry CCR conversion project for Units 3 and 4 of the Chesterfield Power Station;

3. That the Stipulation filed by DENC and CIGFUR is hereby approved in its entirety;

4. That DENC shall recover from its North Carolina retail ratepayers its CCR Costs incurred during the period July 1, 2016, through June 30, 2019;

5. That the Company's CCR Costs shall be amortized and recovered from ratepayers over a ten-year period;

6. That during the amortization and recovery of the CCR Costs the CCR costs shall not earn a return;

7. That DENC shall be allowed to recover its financing costs incurred during the Deferral Period and up to the effective date of new rates approved in this Order, at the Company's previously authorized weighted average cost of capital;

8. That the Company shall use annual compounding for calculating the financing costs deferred costs during the Deferral Period;

9. That DENC shall maintain complete records of all environmental management activity and test results that pertain to its coal ash management program, and make such records available to the Public Staff and the Commission upon request and in the format that is reasonably requested by the Public Staff and the Commission;

10. That as soon as practicable following the issuance of this Order DENC shall file with the Commission the annual revenue requirement and accompanying rate schedules and terms and conditions that are consistent with the findings and conclusions of this Order and the Public Staff Stipulation, with the exception of Section VII.A. The Company shall work with the Public Staff to verify the accuracy of the filing. Further, DENC shall file schedules summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determinations in this proceeding;

11. That DENC is hereby authorized to adjust its rates and charges in accordance with the findings in this Order effective for service rendered on and after the

following day after the Commission issues an Order accepting the calculations required by Ordering Paragraph No. 10;

12. That the Commission shall issue an order as soon as reasonably practicable approving the final revenue requirement numbers once received from DENC and verified by the Public Staff;

13. That the proper jurisdictional average base fuel factor for this proceeding is 2.089¢/kWh, excluding regulatory fee, and 2.092¢/kWh, including regulatory fee. The Company shall replace the voltage-differentiated base fuel factors approved in Sub 532 with the following voltage-differentiated base fuel factors, including regulatory fee, effective February 1, 2020:

Customer Class	Base Fuel Factor
Residential	2.118 ¢/kWh
SGS & PA	2.115 ¢/kWh
LGS	2.098 ¢/kWh
NS	2.036 ¢/kWh
6VP	2.065 ¢/kWh
Outdoor Lighting	2.118 ¢/kWh
Traffic	2.118 ¢/kWh

14. That the jurisdictional and class cost allocation, rate design principles, and service regulations proposed by the Company, and agreed upon in the Public Staff Stipulation, are approved and shall be implemented;

15. That DENC shall implement Rider EDIT as described in Section VIII of the Public Staff Stipulation. Further, although not specifically outlined in the Public Staff Stipulation, it is appropriate that in this proceeding DENC's fully-adjusted cost of service includes the income tax benefit arising from the annual amortization of federal protected EDIT during the test year, thereby incorporating a going-level of federal protected EDIT amortization per the IRC's normalization rules in base non-fuel rates;

16. That as soon as practicable after the date of this Order, DENC shall file for Commission approval five copies of rate schedules designed to comply with the rate design approved in this Order accompanied by calculations showing the revenues that

will be produced by the rates for each schedule. This shall include a schedule comparing the revenue produced by the filed schedules during the test period with the revenue that will be produced under the rate schedules to be approved herein and a schedule illustrating the rates of return by class based on the revenues produced by the rates for each schedule;[27]

17. That as soon as practicable after the issuance of the last Commission Order in DENC's four pending rate-related proceedings, which are this proceeding, the Sub 579 fuel charge adjustment proceeding, the Sub 578 renewable energy and energy efficiency portfolio standard (REPS) cost recovery proceeding, and the Sub 577 demand-side management (DSM) proceeding, DENC shall file a consolidated proposed customer notice addressing the rate changes associated with the non-fuel base and base fuel rate changes approved in this proceeding (Sub 562), the Fuel Rider B in the Sub 579 proceeding, the REPS Rider RP and RPE rate changes in Sub 578, and the DSM Rider C and Rider CE rate changes in Sub 577. Such notice shall include the effect of each rate-related proceeding on a residential customer using 1,000 kWh and the combined effect of all four rate-related proceedings on a residential customer using 1,000 kWh. Upon approval by the Commission, DENC shall notify its North Carolina retail customers of the foregoing rate adjustments by including the approved notice as a bill insert with customer bills rendered during the next regular scheduled billing cycle;

18. That the Company shall continue to annually file a cost of service study with the Commission using the Summer/Winter Peak and Average methodology;

19. That in its next general rate case, the Company shall file the results of a class cost of service study with production and transmission costs allocated on the basis of the Summer/Winter Coincident Peak method in addition to the SWPA used in this proceeding and consider such results for the sole purpose of apportionment of the change in revenue to the customer classes;

20. That if DENC receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company shall continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case;

21. That the Company shall work with CIGFUR to consider whether certain provisions within its RTP rates should be modified and, if there is mutual agreement between CIGFUR and DENC to such modifications, and CIGFUR indicates that at least one of its member customers is willing to take service under such rates, DENC shall re-

[27] If necessary, the Commission will address in a subsequent order any refund due ratepayers based on any differences in the rates approved in this Order and the Company's temporary rates implemented on November 1, 2019.

file such rates with the Commission for approval with the modifications agreed upon within 60 days of such agreement;

22. That within ten days of the resolution by settlement, judgment, or otherwise of the pending and future CCR insurance claims, DENC shall file a report with the Commission explaining the result and stating the amount of insurance proceeds to be received or recovered by DENC. This reporting requirement shall apply even if there is litigation appealed to a higher court;

23. That DENC shall place all CCR insurance proceeds received or recovered by DENC from pending and future insurance claims in a regulatory liability account and hold such proceeds until the Commission enters an order directing DENC as to the appropriate disbursement of the proceeds. The regulatory liability account shall accrue a carrying charge at the net-of-tax overall rate of return authorized for DENC in this Order; and

24. That in DENC's next update of its depreciation study it shall account for its projected CCR waste management facility decommissioning and closure costs in the decommissioning expenses for its coal-fired power plants.

ISSUED BY ORDER OF THE COMMISSION.

This the 24th day of February, 2020.

NORTH CAROLINA UTILITIES COMMISSION

Kimberley A. Campbell

Kimberley A. Campbell, Chief Clerk

Commissioner Daniel G. Clodfelter concurs in part and dissents in part.

DOCKET NO. E-22, SUB 562
DOCKET NO. E-22, SUB 566

Commissioner Daniel G. Clodfelter concurring in part and dissenting in part:

I concur in the result reached by the Commission on all issues save two, and as to those two matters I dissent. In addition, though I join in the outcome on all other matters, some of my thinking on those matters is not fully captured by the Commission's opinion and order, and I write to elaborate my views on certain issues. I address first the two points on which I would reach a different result.

Rate Design and Fixed Monthly Charge

For the reasons set forth in my dissent in the DEC Rate Order in Docket No. E-7, Sub 1146 (June 22, 2018), which I will not repeat here, I do not support the Company's proposal to increase the fixed monthly charge to residential customers and would find the proposal unsupported on this record. My view, as set out in my dissent in the DEC Rate Order, is that the Company's fixed monthly charge should be calculated with reference to cost allocation that employs the "basic customer method" to assign distribution system costs, but in any event the Company's current fixed charge, which relies in part on the "minimum system method" for allocating distribution system costs, should not be increased from its current level. (For a calculation of the results of using the "basic customer method" of cost allocation, see Company's Rate Allocation and Rate Design Late-Filed Exhibit 1.) Accordingly, I dissent as to Finding Number 40 approving the Company's proposed rate design, and therefore also as to Finding Number 66, wherein the Commission finds the Company's proposed rates, except as modified by the Commission's order, to be just and reasonable. I also take note of and agree with Finding Number 15.l., in which the Commission finds that "… some customers [of the Company] will struggle to pay their utility bills under the rate increases authorized herein." I believe this finding counsels against increasing the fixed portion of the Company's rates at this time.

Allowance of Financing Costs During Deferral Period

As to the second point, I dissent from Finding Number 54 and would instead find that the Company is not entitled to recover any amount greater than the approximately $19.2 million actually expended for costs related to waste coal ash during the Deferral Period. More specifically, I would not allow recovery of the approximately $2.7 million the Company has requested as alleged "financing costs" related to the actual $19.2 million in expenditures.[28]

The Commission has determined, and I agree, that neither the Actual CCR Expenditures nor the Deferral Period Return are entitled to earn any return during the

[28] The Commission's order defines the capitalized term "CCR Costs" to include both the $19.2 million in actual expenditures on activities related to coal ash and also the sum of $2.7 million labelled

period of amortization and will not be included in rate base. (Finding No. 53) Much of my reasons for supporting this result are set forth in my dissent in the DEC Rate Order in Docket No. E-7, Sub 1146 (June 22, 2018), and again I will not repeat them here. With respect to the allowance of what the Commission calls "financing costs," however, I can find no supportable basis for differentiating the Deferral Period from the amortization period.

The Commission proffers only one reason for this different treatment.[29] It states:

> …[T]he Commission observes that such a return *may* reduce the incentive for the Company to apply for rate increases more frequently to avoid regulatory lag. While recovering financing costs incurred during the Deferral Period does not help with the Company's short-term cash flow, it means the Company ultimately does not experience lost financing costs if it delays a new rate case.

Order at 135 (emphasis added).

I am unpersuaded by this suggestion because I do not find in the record sufficient evidence that the potential "may" is more likely than not to translate to an actual "will." I find nothing in the evidentiary record that the amount of the Deferral Period Return – approximately $2.7 million – is sufficient to drive the Company's future decisions about whether or not to seek an adjustment of the rates approved in this proceeding. On the record in this case, it is far, far more likely that the timing of future rate change applications will be driven by the planned capital investments identified by Company witness Mitchell and discussed by the Commission in its analysis in support of Finding No. 66 – e.g., the Company's commitment to place into service 3,000 MW of new solar and wind generation capacity by 2022 (Tr. vol. 6, 171-72), the Company's plans to spend some $200 million in transmission upgrades in North Carolina over the next five years (Tr. vol. 6, 173-74), and the Company's overall plan to invest some $11.1 billion in the aggregate in generation, transmission, and distribution system improvements over the next three years. *Id.* at 177. It is expenditures such as these that will determine when the Company next seeks a change in its rates and not whether it is allowed in this case to

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"financing costs." The term "financing costs" is a euphemism for the authorized weighted average cost of capital, which includes the costs of third-party debt but also a return on equity. For clarity, hereafter I will refer to the first component as "Actual CCR Expenditures" and the second component as "Deferral Period Return."

[29] The Commission's order also notes that the Public Staff did not oppose allowing recovering of financing costs during the Deferral Period. This I consider a statement of fact concerning a party's position in the case; it is not a rationale justifying the Commission's decision. The Commission is not constrained by the Public Staff's position; indeed, in this case the Commission has declined to accept the settlement position of the Public Staff concerning the ratemaking treatment of certain costs for the dry ash conversion project as related to Chesterfield Units 3 and 4. Irrespective of the Public Staff's or any other party's position on an issue, the Commission is required to consider all of the evidence and exercise its independent judgment to set just and reasonable rates. *State ex rel. Utilities Commission v. Carolina Utility Customers Ass'n, Inc.*, 348 N.C. 452, 466, 500 S.E.2d 693, 703 (1998).

recover $2.7 million on account of monies already expended on coal ash remediation and closure activities over the three years prior to this case. *Id.* at 177.[30]

Beyond this, I find it difficult to harmonize the Commission's decision on this point with Findings of Fact Nos. 56 through 58 and the discussion and analysis supporting those findings, which I fully endorse and support. The Commission has found that in analyzing, proposing, and seeking the establishment of rates that included allowances for depreciation associated with its coal-fired generating units the Company failed to include any amounts for the costs of final remediation or closure of the waste ash management units associated with these plants. Had the Company done so, then at least some portion, if not all, of the costs for which it now seeks recovery, including the Actual CCR Expenditures for the Deferral Period, would have been recovered as an annual operating expense as part of the rates applicable to service provided in earlier periods.[31] Put differently, had the Company properly anticipated, estimated, and collected as part of depreciation allowance amounts that were later required for Actual CCR Expenditures made during the Deferral Period, it would have thereby accrued a reserve from the revenues earned under prior rates that could have been used to offset or avoid some, if not all, of the Deferral Period Return that it now seeks and that the Commission has approved. I cannot reconcile the Commission's admonishment that the Company did not properly account for or seek recovery of the Actual CCR Expenditures, as part of net salvage value included in depreciation allowance, with the Commission's acceptance of the Company's present request that it be allowed the Deferral Period Return in order to assist in managing the cash flow needs associated with its CCR remediation and closure activities.

The Limitations of Finding Number 51

I concur in the Commission's Finding Number 51. I do so as much because of what is not said in that finding as what is said. The Commission does not in this case find and conclude that the Company – over a period of many years and at multiple sites – prudently

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[30] In this proceeding the Commission authorizes recovery of the Deferral Period Return on a backward-looking basis. It is interesting that neither the Company's stipulation and settlement with the Public Staff in its 2016 general rate case, Docket No. E-22 sub 532, nor the Commission's order in that case discussed the issue of recovery of "financing costs" for expenditures made on CCR remediation and facility closure after June 30, 2016, and during the period prior to the Company's next succeeding general rate case, now the present case. Apparently, in 2016 the Company was willing to go forward to its next rate case with no assurance that it would be able to recover its "carrying costs" on CCR expenditures made in the interim period. Approximately three years elapsed from that time until the present case, and on the present record I am unable to conclude that the timing of the present case was dictated by the "carrying cost" of CCR expenditures instead of by other factors. It is far more likely that the timing of the present case was influenced by the Company's desire to bring the new $1.3 billion Greensville combined cycle plant into rate base.

[31] As noted in the Commission's discussion of the issue, the point here is not that the Company was tasked with perfect foresight as to its ultimate, actual CCR remediation and facility closure costs but instead that it made no reasonable effort to make any estimate of such costs or recover any such estimate as part of depreciation allowances. Had it done so, the cash flow impact of some portion, if not all, of the Actual CCR Expenditures would have been covered by the revenues recorded to recover depreciation expense.

managed waste coal ash. It finds only that the particular items of expenditure for which recovery is sought in this case cannot be causally connected to specifically identifiable imprudent acts or omissions based on the record evidence presented to the Commission. The expenditures at issue in this case would likely have been incurred in all events upon final closure of the waste ash management units. They involved activities such as characterizing the wastes, calculating volumes, preliminary design and engineering of closure plans, legal review and vetting of closure plans, permitting and regulatory oversight activities, water sampling and monitoring, and dewatering and consolidating ash for ultimate disposal. (Although the total cost of these activities is included in DENC's testimony as public information, the separate cost of each activity was filed by DENC under seal as a proprietary trade secret in Confidential Company Late-Filed Exhibits 5 and 6, and Supplemental Late-Filed Exhibit 5). The Public Staff presented no evidence that either the specific activities at issue or the amount of the costs expended were causally related to any acts or omissions that could on the present record be found to be imprudent.

The Commission's order thus preserves for the future certain questions that were not fully explored in the present case. One example of such a question, which I offer for purposes of illustration only, concerns the Company's failure to take prompt steps to permanently stabilize and close the surface impoundments at the Possum Point plant after the plant was converted to natural gas in 2003 and the impoundments ceased receiving coal ash waste. In light of the Company's knowledge of possible groundwater degradation associated with these impoundments (*See* Tr. vol. 6, 145-157), it may be pertinent to examine in greater detail the Company's failure to take action to permanently close the impoundments in 2003 and whether or not the delay in commencing final closure activities until after adoption of the CCR Rule can be causally linked to any subsequent remedial or closure costs that could have been avoided if earlier action had been taken. The parties differ greatly as to the standard of conduct that should be applied in evaluating the Company's actions and omissions at Possum Point in 2003 and prior to the adoption of the CCR Rule, but it is not necessary to decide this point in the present proceeding. I offer this example not to express any judgment on the matter but merely to show that the limited scope of Finding Number 51 may not be a matter of purely theoretical interest.

"Equitable Sharing" By Any Other Name ….[32]

The Commission professes to reject the Public Staff's "equitable sharing" position as being inconsistent with accepted ratemaking principles and attempts to differentiate the Public Staff's position from its own effort to strike a "fair balance" between ratepayers and shareholders.[33] Order at 136-137. I am unable to join in the Commission's reasoning

[32] "What's in a name? That which we call a rose by any other name would smell as sweet …" *Romeo and Juliet,* Act II, Scene II.

[33] E.g. Order at 131, referring to the "well-established history" of Commission decisions seeking to establish a "fair and reasonable" balance between ratepayers and shareholders; Order at 132, referring to the objective of striking "the appropriate balance between shareholder and customer interests to set just and reasonable rates"; and Order at 135, noting that the ten-year period of amortization approved by the

for the straightforward reason that the ultimate result reached by the Commission amounts, in concept, to exactly the same thing as advocated by the Public Staff. The outcome of the Public Staff's proposal and that of the Commission's analysis differs only in the fact that the Public Staff recommended an eighteen-year period of amortization of allowed costs rather than the ten-year amortization period adopted by the Commission. Indeed, much of the reasoning offered by the Commission is the same as that invoked by the Public Staff to support its own "equitable sharing" proposal, including the Commission's reliance on the analysis and authority of, among other precedent, the MGP Order and the Anna/Surry Order. Order at 130-131.[34]

I concur with both the Commission's order and with the Public Staff that there is ample legal basis for the Commission to allocate or divide the cost burden between ratepayers and the Company's shareholders. For myself, the point of difference I have with the Public Staff is not over the concept of "equitable sharing" or the legal basis for application of that concept, but over the specific equities of this case that warrant invoking it. I find sufficient support for the result reached by the Commission in the analysis and discussion associated with Findings of Fact Numbers 56 through 58, and I do not need to go further than the scope of those findings to reach that result. The Company's failure to make any provision over the useful lives of its coal-fired generating plants for recovery of the ultimate costs of remediation and closure of waste coal ash management facilities is ample ground for the Commission to find that a portion of the costs now incurred for such remediation and closure must be borne by the Company itself and not by present and future ratepayers. The Commission's selection of a ten-year period for amortization of those costs achieves a fair and reasonable balance of cost-sharing between ratepayers and the Company.

A Question for the Future

Following promulgation of the CCR Rule, the Company's plan for closure of waste ash surface impoundments at all of its plants was to dewater the ash, place a permanent cap over the contents, and close the impoundments in place. This plan has been superseded by the adoption of Virginia Senate Bill 1355, codified at Va. Code Ann. §10.1-1402.03 (2019) (the Chesapeake Coal Ash Act) for the waste ash management units located within the Chesapeake Bay watershed. The Chesapeake Coal Ash Act applies to the coal ash management units at the Company's Bremo, Possum Point, Chesapeake and Chesterfield plants, requiring the excavation and removal of waste ash for permanent disposal outside the watershed. Company witness Williams testified that the impact of this legislation did not increase any of the costs or change any of the activities for which cost recovery is requested in this case but that the Act may likely affect

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Commission "…strikes the more appropriate and fairer balance" than does the position of either the Company or the Public Staff.

[34] The Commission's reasoning that most closely parallels the Public Staff's "equitable sharing" analysis is contained in its discussion of whether the Company should be allowed to earn a return on the unamortized balance of the CCR Costs (Order at 130-134), but I consider immaterial the rubric under which the discussion is placed. I acknowledge, of course, that the Commission does not rely upon the Public Staff's notion of "culpability." With this difference, however, the analysis otherwise runs very similarly.

future impoundment closure activities and the resulting costs for which recovery will be sought in future rate cases. Tr. vol. 5, 93. I believe it is important, because the parties did not develop the issues in their evidentiary presentations or their briefing and because on this record it is not ripe for decision, that the Commission signal to the parties that two potential matters remain for determination in future rate cases: (1) whether the Company's record of management of waste coal ash, especially with respect to the surface impoundments at the four plants affected by the Chesapeake Coal Ash Act, may have prompted or contributed to the Act's elimination of the Company's preferred "cap in place" closure method and, if it did so, to what extent the costs of remediation and final closure of those waste management facilities may be increased due to requirements of the Act more stringent than those of the CCR Rule, and (2) whether or not, independently of the preceding question, any incremental or enhanced costs resulting from compliance with the Chesapeake Coal Ash Act may be recovered from North Carolina ratepayers. The first of these questions speaks to an issue of prudence; the second is jurisdictional. I express no view on either of these questions at this time, but I note that the Company and other interested parties should be prepared, in the appropriate proceeding and at the appropriate time, to present evidence concerning the amount, if any, by which the Company's coal ash remediation and waste management facility closure costs at the Bremo, Possum Point, Chesapeake, and Chesterfield plants were or have been increased, due to changes in scope or extent, over what those costs would have been had those waste management facilities been remediated and closed under the provisions of the CCR Rule.

/s/ Daniel G. Clodfelter

Commissioner Daniel G. Clodfelter