the construction of a generating plant must comply with the major case filing requirements provided for by the Public Utility Act and the rules and regulations of this Commission. This requires voluminous financial and other data which would not be filed under an ordinary evaluation under PEP-2. It also requires that a projected test year for determining rates be used instead of the historic test year used in the PEP-2 periodic evaluations. It allows for recovery of an increase in revenues in excess of the 2% of retail revenues, if such is justified.

Neither the "Major Plant" section nor any other section of PEP-2, eliminates the need to perform a calculation of performance to determine whether a change, up or down, should be made so as to reflect MPCo's performance. This is by design. This Commission has since 1985 required that MPCo's rates be adjusted for performance in those areas which most affect the customers -- currently price, reliability and customer satisfaction. We never intended that any rate for MPCo set under PEP-2 or any of its provisions ignore performance.

When this matter was filed, we did not void PEP-2 as the rate method for MPCo, we simply suspended the semi-annual rate evaluation to be made under it. This allowed us to litigate the matters required under the "Major Modification" section and to use the remaining provisions to determine just and reasonable rates for MPCo.

The use of a projected test year, as required here, evaluates MPCo for the year 2002. It would have been counter-productive to evaluate MPCo's need for rates under PEP-2 prior to the end of the 2002 test year. This was the reason we have concluded in accord with the Stipulation, that the semi-annual rate evaluations would only resume based on the historic 12 months ended December 31, 2002. This will also give this Commission a second evaluation, based on actual, historic data of the same period for which rates are to be made here on the projected 2002 year.

The procedure for the calculation of the Company's revenue requirements in this docket, which we find to be consistent with PEP-2, is as follows:

a. The rate base, revenues and expenses, capital structure, and weighted cost of debt, trust preferred stock and preferred stock included in the filing, as modified by the Stipulation and approved herein, shall be used.

b. The return on common equity, as determined herein and adjusted by .25% for flotation costs shall be used as K_{AVG} in the PEP-2 calculation, as PEP-2 is modified by the Stipulation, using the Company's performance as of December 31, 2000, as was used by Dr. Garbacz.

c. Based on this procedure, the Commission finds that the rates determined herein are just and reasonable.

The Company shall determine its revenue requirements for the test year on the basis of this order; shall allocate that revenue requirement to its rate schedules and special contracts; and shall file revised rate schedules reflecting the change.

Although not mentioned in the testimonies of the parties in this docket, the Company included in its test year expenses one-third of the total estimated amount of the costs it expected to incur in this docket. Beginning in 2002, the total costs incurred by MPCo in this docket shall be amortized over a period not to exceed 36 months.

This order shall be effective upon issuance.

Chairman Nielsen Cochran voted Aye; Vice-Chairman Michael Callahan voted Aye; Commissioner Bo Robinson voted Aye.

SO ORDERED by the Commission on this the 3rd day of December, 2001.

MISSISSIPPI PUBLIC SERVICE COMMISSION

Nielsen Cochran, Chairman

Michael Callahan, Vice Chairman

Bo Robinson, Commissioner

ATTEST: A True Copy

Brian U. Ray,
Executive Secretary

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

Keyspan Gas East Corporation d/b/a National Grid and
The Brooklyn Union Gas Company d/b/a National Grid NY

Cases 16-G-0058 and 16-G-0059

May 2016

Prepared Testimony of:

Jeremy Routhier-James
Utility Analyst 3
Office of Accounting, Audits and Finance

State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

Q. Please state your name, employer, and business address.

A. My name is Jeremy Routhier-James. I am employed by the New York State Department of Public Service at Three Empire State Plaza in Albany, New York, 12223.

Q. What is your position in the Department?

A. I am employed as a Utility Analyst 3 in the Management and Operations Audit Unit of the Office of Accounting, Audits and Finance.

Q. Please describe your educational background and professional experience.

A. I hold a Bachelor of Arts in Sociology from the State University of New York at Albany and a Master of Public Administration from Marist College. I have been employed by the Department since April 2008, and have worked in the Management and Operations Audit Unit since September 2010. I am responsible for the oversight of management and operations audits, as well as the implementation of the resulting recommendations.

Q. Have you supervised management and operations audits of New York State utilities?

A. Yes. I have served as Project Manager for several management and operations audits of utility companies. In this role, I have been responsible for leading the development of the Request for Proposals which defines the scope of each audit, leading the Staff team which selects the independent consultants to perform the audits, overseeing and participating in audit field work, and reviewing and communicating audit findings and recommendations to Staff and the Commission. I have also managed the implementation of audit recommendations as Implementation Manager for several management and operations audits. In this role, I have been responsible for ensuring that utility companies submit timely implementation updates, reviewing the completion of audit recommendation implementation, and reporting implementation status to Staff and the Commission. Finally, I serve as the Department's subject matter expert in corporate governance and performance management for management and operations audits. In this role, I have been responsible for developing audit scope components, monitoring and reporting on audit findings, and overseeing and reviewing utility implementation of audit recommendations related to corporate governance and performance management. My specific audit responsibilities have included, among other things, three management and operations audits of National Grid USA's companies.

Q. In what cases have you performed these functions?

A. I am the Implementation Manager for Case 08-E-0827, a Comprehensive Management Audit of Niagara Mohawk Power Corporation d/b/a National Grid's Electric Business. This audit examined the electric operations of Niagara Mohawk Power Corporation (NMPC) and that company's shared management with other National Grid USA companies, including the Brooklyn Union Gas Company d/b/a National Grid NY (KEDNY) and KeySpan Gas East Corporation d/b/a National Grid (KEDLI).

Q. Are you involved in any other cases?

A. I am the Project Manager and Implementation Manager for Case 10-M-0451, a Proceeding on Motion of the Commission to Investigate National

Grid Affiliate Cost Allocations, Policies and Procedures. This audit examined certain affiliate transactions between various National Grid USA companies, including KEDNY and KEDLI (the Companies), and the policies and procedures governing such. Finally, I am the Project Manager and Implementation Manager for Case 13-G-0009, a Comprehensive Management and Operations Audit of National Grid USA's New York Gas Companies. This audit examined the gas operations of NMPC, KEDNY, and KEDLI, as well as the shared management with other National Grid USA companies. I am also the subject matter expert for corporate governance and performance management in this audit, and I presented the audit's findings and recommendations to the Commission at its October 2, 2014 session. Implementation efforts for Case 10-M-0451 were completed in June 2015. Implementation for Cases 08-E-0827 and 13-G-0009 is ongoing.

Q. Have you previously testified before the Commission?

A. No.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring one exhibit, Exhibit____(JRJ-1).

Q. Will you refer to any information provided by KEDNY and KEDLI during the discovery phase of this proceeding in your testimony?

A. Yes. I will refer to, and have relied upon, responses to Information Requests (IRs) provided by KEDNY and KEDLI. These responses are contained in Exhibit____(JRJ-1).

Q. What is the purpose of your testimony in this proceeding?

A. Public Service Law, Section 66(19)(c), requires that "upon the application of a gas or electric corporation for a major change in rates…the commission shall review that corporation's compliance with the directions and recommendations made previously by the commission, as a result of the most recently completed management and operations audit." Accordingly, my testimony will address KEDNY and KEDLI's overall compliance with the May 14, 2015 "Order Approving an Implementation Plan" in Case 13-G-0009 related to the comprehensive management and operations audit of National Grid

USA's New York gas companies, performed by NorthStar Consulting Group.

Q. When was the NorthStar audit completed?

A. NorthStar's final audit report was issued on October 2, 2014. NorthStar's report contained 31 recommendations for improvement at KEDNY, KEDLI, and NMPC. Each recommendation was accompanied by a Customer Benefit Analysis which detailed anticipated costs and benefits associated with implementing the recommendations, as well as potential risks of not implementing the recommendation. NorthStar's Customer Benefit Analyses were developed using information provided by KEDNY, KEDLI, and NMPC, and included qualitative and quantitative cost and benefit estimates, as appropriate. KEDNY and KEDLI witness Ms. Keri Sweet Zavaglia, on pages three through five of her testimony, provides additional information related to the audit's background, findings, and recommendations.

Q. What are a utilities' responsibilities regarding the outcome of a management and audit report?

A. When the Commission issues a management and operations audit report, utilities are required by Public Service Law §66(19) to submit implementation plans for audit recommendations to the Commission. The Commission may then approve, modify, or reject the submitted implementation plan. Upon the Commission's approval or approval with modification, the implementation plan becomes enforceable. A staff team of subject matter experts is responsible for monitoring the utility's implementation of the audit recommendations. As utilities implement the recommendations, they submit evidence of successful implementation to Staff for review and approval. Accordingly, audit recommendations generally fall into one of three categories of completion status: In Progress, Pending Review (reported as complete by the utility but under review by Staff), and Completed.

Q. Where in the audit process are KEDNY and KEDLI?

A. KEDNY, KEDLI, and NMPC filed their initial implementation plan for Case 13-G-0009 with the Secretary for the Department on November 3, 2014. Certain changes were made to the initial implementation plan as a result of subsequent discussions with Staff and decisions within National Grid USA to modify the plan in certain ways. KEDNY, KEDLI, and NMPC filed a revised implementation plan with the Secretary for the Department on April 21, 2015. The ensuing Commission "Order Approving an Implementation Plan" was issued on May 14, 2015, and directed KEDNY, KEDLI, and NMPC to implement the recommendations resulting from the audit consistent with the revised implementation plan dated April 21, 2015. Hereafter, I will refer to the revised implementation plan dated April 21, 2015, and approved by the Commission on May 14, 2015, as the "Approved Implementation Plan."

Q. What is the status of KEDNY and KEDLI's overall compliance with the Commission's aforementioned "Order Approving an Implementation Plan" in Case 13-G-0009?

A. KEDNY and KEDLI, along with NMPC, have filed timely written implementation updates and have met with Staff between written updates in accordance with the Order. The latest implementation filing was submitted on January

20, 2016. This filing identifies 17 recommendations as Pending Review and 14 recommendations as In Progress. This means KEDNY, KEDLI, and NMPC have reported that 17 recommendations have been implemented and the remaining 14 are underway. The 17 recommendations listed as Pending Review are currently under review by a team of Staff subject matter experts, consistent with the process explained above. At this time, no recommendations are considered Completed.

Q. Have KEDNY and KEDLI included costs resulting from implementation of the audit recommendations in their rate filings?

A. Yes. Pages 1 and 2 of the Companies' response to information request DPS-286, which is contained in Exhibit____(JRJ-1), state that the Companies have included in their revenue requirements costs to implement two audit recommendations which are expected to involve material implementation costs. These are Recommendation VI-2 to develop a Gas Estimating Department and Recommendation IX-4 to modify policies and procedures related to supply procurement.

Q. Please explain Recommendation VI-2.

A. Recommendation VI-2 directs the Companies to "develop an estimating program for gas projects that is consistent with that used for NG USA's electric utilities." In addition to performing the audit in Case 13-G-0009, NorthStar performed the management audit of NMPC's electric business in Case 08-E-0827. Though Case 08-E-0827 was limited to NMPC's electric operations, the audit findings are relevant due to the shared management structure of National Grid's utilities. In its Final Report in Case 08-E-0827, dated December 4, 2009, on pages VIII-13 through VIII-15, NorthStar found that National Grid's US management had "long recognized that estimating of complex construction projects [was] a problem," and during the audit NMPC was in the process of implementing a new department called the Estimating Center of Excellence to address the known deficiency. At the time, NorthStar recommended NMPC continue those efforts with the intent of improving performance related to project estimating. Due to the scope of that audit, the findings and recommendations were limited to NMPC's electric operations.

Q. What effect did this recommendation have on KEDNY and KEDLI?

A. When NorthStar reviewed KEDNY, KEDLI, and NMPC's gas operations in Case 13-G-0009, it found similar issues related to poor project estimating on the gas side of the business. While efforts had been made in the meantime to improve electric transmission and distribution project estimating, those efforts had not been extended to gas projects. NorthStar recommended that KEDNY, KEDLI, and NMPC develop an improved estimating program based on the electric estimating program at NMPC.

Q. What impact or savings would result from the implementation of this change, as recommended?

A. NorthStar's Customer Benefit Analysis for Recommendation VI-2 did not quantify potential savings from implementing this recommendation. However, the consultant noted that accurate project estimates allow improved analysis, facilitate an optimized capital portfolio, and reduce delays, rework, redesign, scope modifications, rebidding, inefficient procurement, and permit extensions. This results in productivity savings across all aspects of the project.

Q. Please describe KEDNY and KEDLI's plan to implement Recommendation VI-2.

A. The Companies, along with NMPC, proposed in the Approved Implementation Plan to establish a Gas Estimating Department consistent with NorthStar's recommendation. The Approved Implementation Plan indicated that the new department would be staffed by four engineers, two analysts, and one director, and would manage approximately 200-225 complex projects annually for the Companies and NMPC. The plan projected that the new department would be established within 12 to 18 months, with staffing of the department occurring in the second quarter of 2015, training and estimating tool enhancements occurring during the fourth quarter of 2015, and final implementation occurring in the second quarter of 2016, with the new department estimating projects for Fiscal Year (FY) 2018. The plan projected annual costs to staff and operate the new department to be approximately $1.29M for capital expenses and $0.31M for operating expenses for KEDNY, KEDLI, and NMPC. The Approved Implementation Plan did not quantify potential savings, but noted that improved estimate accuracy and the delivery of complex projects within expectations drives efficiency improvements in the execution of the Capital Business Plan.

Q. Are the Companies implementing Recommendation VI-2 consistent with the terms of the Approved Implementation Plan?

A. Page 2 of the Companies' response to IR DPS-412, contained in Exhibit____(JRJ-1), states that "National Grid intends to fill the majority of the positions in the Gas Estimating Department in fiscal year 2017." This is well outside of the time frame in the Approved Implementation Plan, which indicated the new department would be staffed in the second quarter of 2015. Additionally, the Companies' responses to IRs DPS-286 and DPS-412, contained in Exhibit____(JRJ-1), indicate that the Companies' revenue requirements include the costs for seven

FTEs in the new Gas Estimating Department who are expected to manage over 125 complex projects annually for KEDNY and 100 complex projects annually for KEDLI. The seven FTEs include six estimators and one manager. These seven FTEs would only perform work for the Companies, not NMPC. This represents a significant staffing level increase from the Approved Implementation Plan, which envisioned seven FTEs providing services to the Companies and NMPC. However, the volume of work (225 projects annually for the Companies), appears consistent with the expectations laid out in the Approved Implementation Plan. Therefore, the staffing increase for the Companies is inconsistent with the approved plan.

Q. Please explain Recommendation IX-4.

A. Recommendation IX-4 was to "modify policies and procedures covering the monthly and daily supply procurement forecasting." The recommendation included a list of specific improvements to KEDNY, KEDLI, and NMPC's supply procurement policies and procedures. The intent of this recommendation was to address NorthStar's finding that KEDNY, KEDLI, and NMPC did not retain initial day-ahead or daily forecasts for review and identification of improvement opportunities.

Q. What impact or savings correspond to the implementation of this change, as recommended?

A. NorthStar's Customer Benefit Analysis for Recommendation IX-4 projected that KEDNY, KEDLI, and NMPC would need to add one FTE to perform the recommended analysis. The consultant did not quantify any potential savings because KEDNY, KEDLI, and NMPC did not previously maintain data necessary to assess the accuracy of the forecasts, hence the recommendation to do so. However, the consultant noted that even a 0.1% reduction in the cost of gas would pay for the additional FTE. The consultant also noted that the analyst position could be eliminated after two years if the resulting analysis determined that existing forecast procedures were of sufficient accuracy.

Q. Please describe KEDNY and KEDLI's plan to implement Recommendation IX-4.

A. The Companies, along with NMPC, proposed in the

Approved Implementation Plan to enhance their policies and procedures consistent with NorthStar's recommendation. To facilitate this, the Companies, along with NMPC, would hire one additional FTE during 2015 to perform the recommended analysis related to supply procurement and load forecasting, at a cost of approximately $150,000 per year.

Q. Are the Companies implementing Recommendation IX-4 consistent with the terms of the Approved Implementation Plan?

A. Page 2 of the Companies' response to IR DPS-286, which is contained in Exhibit____(JRJ-1), states that an additional FTE is being hired in Energy Procurement. KEDNY and KEDLI's allocable shares of the annual labor costs for the new position are approximately $65,000 and $30,000, respectively. This is consistent with the Approved Implementation Plan, with the exception of the timing of the new hire, which is still pending. The Approved Implementation Plan indicated the position would be filled in 2015.

Q. Are there cost savings reflected in the Companies' Revenue Requirement as a result of this recommendation?

A. Any benefits resulting from this recommendation would affect the cost of gas supply, which is not included in the Companies' delivery revenue requirement.

Q. Did NorthStar project material savings for any other recommendations resulting from Case 13-G-0009 which would be expected to materialize during the Rate Year?

A. NorthStar's Customer Benefit Analyses did not include quantified anticipated savings for many recommendations. This was generally due to the nature of the recommendations made. For example, the consultant made a number of recommendations related to the Boards of Directors of National Grid USA and its New York operating companies, organizational structure, and risk management. These kinds of recommendations often have desirable implications for governance, planning, and oversight, but those implications tend not to materialize as dollar savings. Other recommendations, such as Recommendation VI-2 discussed above, are expected to result in productivity savings, but such savings are difficult to quantify. NorthStar's Customer Benefit Analyses for Recommendation VII-1 related to tracking and managing crew and individual worker productivity, and Recommendation VII-2 related to a manpower planning program, include such productivity savings projections. However, KEDNY, KEDLI, and NMPC are still in the early stages of implementing these recommendations.

Q. In what way will these recommendations have an impact on KEDNY and KEDLI's customers?

A. Recommendations such as Recommendation IX-4 discussed above, might produce gas supply savings which would be passed along to customers if and when they materialize.

Q. Did NorthStar propose additional recommendations that do not have a direct impact or immediate operational effect on the Companies?

A. Case 13-G-0009 also included two recommendations for KEDNY, KEDLI, and NMPC to conduct certain studies related to specific utility costs. Depending on the findings of the cost studies, NorthStar's Customer Benefit Analyses projected that additional savings could occur. The first of these was Recommendation IV-1, concerning costs related to National Grid USA's implementation of SAP, a financial software platform. The second was Recommendation IX-6 related to potentially misallocated labor costs from the Energy Procurement group. The Companies, along with NMPC, delivered those cost studies to Staff as part of the audit implementation process. Staff has reviewed those reports and will discuss them as part of the Staff Accounting Panel.

Q. As a result of your review of the Company's management and operations audit compliance efforts, do you recommend an adjustment to the Company's rate request?

A. As discussed above, for Recommendation VI-2 related to the Gas Estimating Department, the Approved Implementation Plan envisioned seven FTEs performing work for the Companies and NMPC. However, the Companies' rate filings propose seven FTEs performing a similar volume of work for just KEDNY and KEDLI. The Companies should implement the Gas Estimating Department consistent with the Approved Implementation Plan. Accordingly, a reduction in the number of FTEs is warranted. The number of Estimator positions should be reduced to two for each Company. The Manager position should split its time with NMPC, consistent with the Approved Implementation Plan, thereby reducing the allocable portion of the Manager position for each of the Companies from 0.5 to 0.33. This information is also reflected in the Staff Accounting Panel's testimony.

Q. What is the revenue requirement impact of these reductions in FTEs?

A. The Staff Accounting Panel provided the following information about the impact of these labor adjustments on the Companies' revenue requirement: For KEDNY, the removal of one FTE Gas Estimator and the reduction of the time allocation for the Gas Estimator Manager FTE from 0.5 to 0.33 results in a downward adjustment to other initiative expense of $8089, which includes $5232 in labor and $2857 in adders. For KEDLI, the removal of one FTE Gas Estimator and the reduction of the time allocation for the Gas Estimator Manager FTE from 0.5 to 0.33 results in a downward adjustment to other initiative expense of $8618, which includes $5232 in labor and $3386 in adders.

Q. Do you have any additional recommendations or adjustments to the Companies' proposals for implementation of these recommendations?

A. The Companies' implementation timeline for Recommendation VI-2 effectively and significantly delays the materialization of any resulting productivity savings. Given the increase in capital spending related to gas infrastructure proposed by the Companies in their current rate filings, the Companies would have been better positioned to realize productivity savings resulting from improved estimating if they had moved faster to improve their gas project estimating function. Further, the enterprise-wide issue of inaccurate complex construction project estimates was identified by National Grid's US management and NorthStar as far back as Case 08-E-0827 in 2009. Yet, similar issues on the gas side of the business remained unaddressed in 2014 when the field work for Case 13-G-0009 occurred. Improved estimating of complex construction projects should produce meaningful productivity improvements, and the Companies should have addressed the known deficiencies in gas project estimating function more swiftly. For those reasons, an increase in the productivity adjustment is warranted. The productivity adjustment is being addressed by the Staff Accounting Panel.

Q. Are KEDNY or KEDLI the subject of any other recent management and operations audits?

A. Yes. Both companies, along with other major gas and electric utilities in New York, are the subject of two multi-utility operations audits. The first is Case 13-M-0314, the Review of the Accuracy and Effectiveness of Certain Reliability and Customer Service Systems at all Gas and Combination Gas and Electric Utilities in New York State that Provide Statistics to the Commission on the Services They Provide Customers. The audit was conducted by Overland Consulting and examined the accuracy of the programs and processes used at the companies to collect data on reliability, safety, and customer service, and the accuracy of the calculations of this data as reported to the Department and the Commission. The final report from this audit was released by the Commission on April 20, 2016.

Q. What is the second case the Companies are subject to?

A. The second is Case 13-M-0449, the Focused Operations Audit of the Internal Staffing Levels and the Use of Contractors for Selected Core Utility Functions at Major New York Energy Utilities. This audit is a focused operations audit of the internal staffing levels and the use of contractors for core utility functions at major New York energy utilities. The audit is being performed by Liberty Consulting Group and examined the internal staffing of certain core utility functions, as well as the criteria and controls used for the use of external staffing. This audit is ongoing and the final report is expected to be released later in 2016.

Q. Does this conclude your testimony at this time?

A. Yes.

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

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[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.

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[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.,* 320U.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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> . . .
>
> [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.

In reality, the concept of a fair rate of return represents a "zone of reasonableness." As explained by the Pennsylvania commission:

> There is a range of reasonableness within which earnings may properly fluctuate and still be deemed just and reasonable and not excessive or extortionate. It is bounded at one level by investor interest against confiscation and the need for averting any threat to the security for the capital embarked upon the enterprise. At the other level it is bounded by consumer interest against excessive and unreasonable charges for service.

As long as the allowed return falls within this zone, therefore, it is just and reasonable. . . . It is the task of the commissions to translate these generalizations into quantitative terms.

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

2013 DEP Rate 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

[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